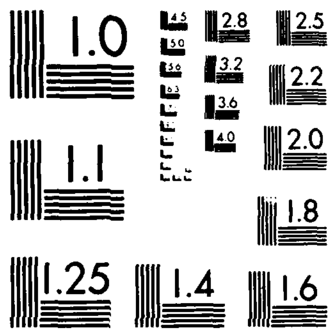
AD-A189 306 A PC SIMULATION OF HEAT TRANSFER AND TEMPERATURE DISTRIBUTION IN A CIRCULATING WELLBORE(U) ARMY MILITARY PERSONNEL CENTER ALEXANDRIA VA R D PIERCE 19 NOV 87 1/2

UNCLASSIFIED F/G 8/7 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

A PC Simulation of Heat Transfer and Temperature
Distribution in a Circulating Wellbore

Captain Robert Duane Pierce
HQDA, MILPERCEN (DAPC-OPB-E)
200 Stovall Street
Alexandria, VA 22332

Final Report 19 November 1987

A thesis submitted to Texas A&M University,
College Station, Texas 77843
in partial fulfillment of the requirements for the
Master of Science in Petroleum Engineering

SECURITY CLASSIFICATION OF THIS PAGE

REPORT DOCUMENTATION PAGE

Form Approved
OMB No 0704 0188
Exp Date Jun 30 1986

1a REPORT SECURITY CLASSIFICATION

1b RESTRICTIVE MARKINGS

2a SECURITY CLASSIFICATION AUTHORITY

3 DISTRIBUTION/AVAILABILITY OF REPORT

2b DECLASSIFICATION/DOWNGRADING SCHEDULE

4 PERFORMING ORGANIZATION REPORT NUMBER(S)
"A PC Simulation of Heat Transfer and Temperature Distribution in a Circulating Wellbore"

5 MONITORING ORGANIZATION REPORT NUMBER(S)
Final Report
19Nov87

6a NAME OF PERFORMING ORGANIZATION

6b OFFICE SYMBOL (If applicable)

7a NAME OF MONITORING ORGANIZATION
HQDA
MILPERCEN (DAPC-OPG-Q)

6c ADDRESS (City, State, and ZIP Code)

7b ADDRESS (City, State, and ZIP Code)
200 Stoval St.
Alexandria, VA 22332

8a. NAME OF FUNDING/SPONSORING ORGANIZATION

8b OFFICE SYMBOL (If applicable)

9. PROCUREMENT INSTRUMENT IDENTIFICATION NUMBER
Student
HQDA MILPERCEN(DAPC-OPA-E) 200 Stovall St. Alexandria, VA 22332

8c. ADDRESS (City, State, and ZIP Code)

10. SOURCE OF FUNDING NUMBERS

PROGRAM ELEMENT NO	PROJECT NO	TASK NO	WORK UNIT ACCESSION NO

11 TITLE (Include Security Classification)
HQDA 200 Stovall St.
MILPERCEN (DAPC-OPA-E) Alexandria, VA 22332

12 PERSONAL AUTHOR(S)
19 Nov 1987

13a TYPE OF REPORT
Thesis

13b TIME COVERED
FROM 850816 TO 871212

14 DATE OF REPORT (Year, Month, Day)

15 PAGE COUNT
157

16 SUPPLEMENTARY NOTATION

Approved for public release. Distribution unlimited.

17 COSATI CODES

FIELD	GROUP	SUB-GROUP

18 SUBJECT TERMS (Continue on reverse if necessary and identify by block number)

Thesis, Texas A&M University

19 ABSTRACT (Continue on reverse if necessary and identify by block number)

The ability to accurately predict temperatures in a circulating wellbore is probably more critical today than at any time in the history of drilling oil wells. Due to the increasing depths to which wells are being drilled, accurate methods and procedures are needed to predict fluid temperatures during circulation operations. These methods and procedures would be used to provide accurate data for designing drilling mud systems and cement jobs for these deep, hot wells.

Though the problem of accurately predicting temperatures in a wellbore has existed since engineers first began searching for oil at greater depths, relatively little has been done to address this problem. In the past it has been convenient to ignore temperature gradients, largely because no practical means for estimating wellbore temperature profiles have been available. Determining accurate temperature distributions in a circulating wellbore is very important for many aspects of drilling, completion, production and injection. (over)

20 DISTRIBUTION/AVAILABILITY OF ABSTRACT
XX UNCLASSIFIED/UNLIMITED ☐ SAME AS RPT ☐ DTIC USERS

21 ABSTRACT SECURITY CLASSIFICATION

22a NAME OF RESPONSIBLE INDIVIDUAL

22b TELEPHONE (Include Area Code)

22c OFFICE SYMBOL

DD FORM 1473, 84 MAR

83 APR edition may be used until exhausted.
All other editions are obsolete.

SECURITY CLASSIFICATION OF THIS PAGE

cont'd 19.

Numerous large-scale temperature simulators have been developed by many researchers. However, these simulators are restricted in their applicability because of their complexity and limited portability. As an alternative, a model has been developed for the personal computer which is portable, flexible, and easy to use.

The model logically organizes the required data into categories. Previous data files can be re-entered and modified as need be. Menus are used to control the program and select different options. A liberal portion of on-screen computer graphics is included to insure that the model is truly "user friendly." The results of the simulator have been compared with published information from other models. The comparison shows that a small scale model can be designed for and operated on a personal computer, include a considerable amount of user interactiveness, and maintain realism and accuracy.

Also, the results of a parametric sensitivity analysis carried out using the model are discussed. The outcome demonstrates that certain parameters which may have been ignored in previous work, have a significant effect on wellbore temperature profiles.

A PC SIMULATION OF HEAT TRANSFER AND TEMPERATURE

DISTRIBUTION IN A CIRCULATING WELLBORE

A Thesis

by

ROBERT DUANE PIERCE

Approved as to style and content by:

Hans C. Juvkam-Wold
(Chair of Committee)

James E. Russell
(Member)

Earl R. Hoskins
(Member)

W D. Von Gonton
(Head of Department)

December 1987

ABSTRACT

A PC Simulation of Heat Transfer and Temperature
Distribution in a Circulating Wellbore
(December 1987)

Robert Duane Pierce, B.S., South Dakota School
of Mines and Technology
Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

The ability to accurately predict temperatures in a circulating wellbore is probably more critical today than at any time in the history of drilling oil wells. Due to the increasing depths to which wells are being drilled, accurate methods and procedures are needed to predict fluid temperatures during circulation operations[1]. These methods and procedures would be used to provide accurate data for designing drilling mud systems and cement jobs for these deep, hot wells.

Though the problem of accurately predicting temperatures in a wellbore has existed since engineers first began searching for oil at greater depths, relatively little has been done to address this problem. In the past it has been convenient to ignore temperature gradients, largely because no practical means for estimating wellbore temperature profiles have been available[2]. Determining accurate temperature distributions in a circulating wellbore is very important for many aspects of drilling, completion, production, and injection.

Numerous large-scale temperature simulators have been developed

by many researchers. However, these simulators are restricted in their applicability because of their complexity and limited portability. As an alternative, a model has been developed for the personal computer which is portable, flexible, and easy to use.

The model logically organizes the required data into categories. Previous data files can be re-entered and modified as need be. Menus are used to control the program and select different options. A liberal portion of on-screen computer graphics is included to insure that the model is truly "user friendly." The results of the simulator have been compared with published information from other models. The comparison shows that a small scale model can be designed for and operated on a personal computer, include a considerable amount of user interactiveness, and maintain realism and accuracy.

Also, the results of a parametric sensitivity analysis carried out using the model are discussed. The outcome demonstrates that certain parameters which may have been ignored in previous work, have a significant effect on wellbore temperature profiles.

ACKNOWLEDGEMENTS

The author wishes to express his most heartfelt thanks to the following individuals:

Dr. H.C. Juvkam-Wold, Professor of Petroleum Engineering and Chairman of the author's Graduate Committee, for his genuine interest, thoughtful guidance, helpful assistance, and unselfish gift of personal time and energy. Dr. Juvkam-Wold believed in the author even when the author didn't always believe in himself.

Dr. J.E. Russell, Professor of Petroleum Engineering and Geophysics, and Dr. E.R. Hoskins, Professor of Geophysics, of Geology and Geography and Head, Department of Geophysics, for graciously serving on the author's Committee. Their input into this project proved to be invaluable.

The author would also like to acknowledge the United States Army, under whose auspices this research was accomplished.

DEDICATION

This thesis is dedicated to my wife Candy. She has been my partner in marriage and life for ten years. Her encouragement and assistance were as responsible for this thesis as the knowledge and sweat that is written in it. Without her strong support and gentle, persistent prodding, I would not have had the determination to finish.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES (CONTINUED)

LIST OF FIGURES (continued)

INTRODUCTION

The objective of this research is to develop a small scale computer program for use on a standard personal computer which will accurately model conductive and convective heat transfer processes in a flowing wellbore. Ultimately, this model will assist in providing a greater degree of accuracy in the prediction of temperature in a flowing wellbore. The computer model will incorporate only those parameters that have a significant effect on the system dynamics, maintaining a high degree of accuracy and realism. The proposed computer model will be very interactive and informative, using on-screen menus and graphics. A flow chart of the model is found at Fig.1. The resulting simulator will be relatively fast running and flexible, making it an effective tool for well planning or for designing various cement jobs. The program will be written on a 5.25 inch floppy disk, making it usable in the office or at the well site.

The ability to accurately predict temperatures in a circulating wellbore is probably more critical today than at any time in the history of drilling oil wells. Due to the increasing depths to which wells are being drilled, accurate methods and procedures are needed to predict fluid temperatures during circulation operations.[1] These methods and procedures would be used to provide adequate data for correctly designing drilling mud systems and cement jobs for these deep, hot wells. Though the problem of accurately predicting

---

This thesis follows the style of the Journal of Petroleum Technology

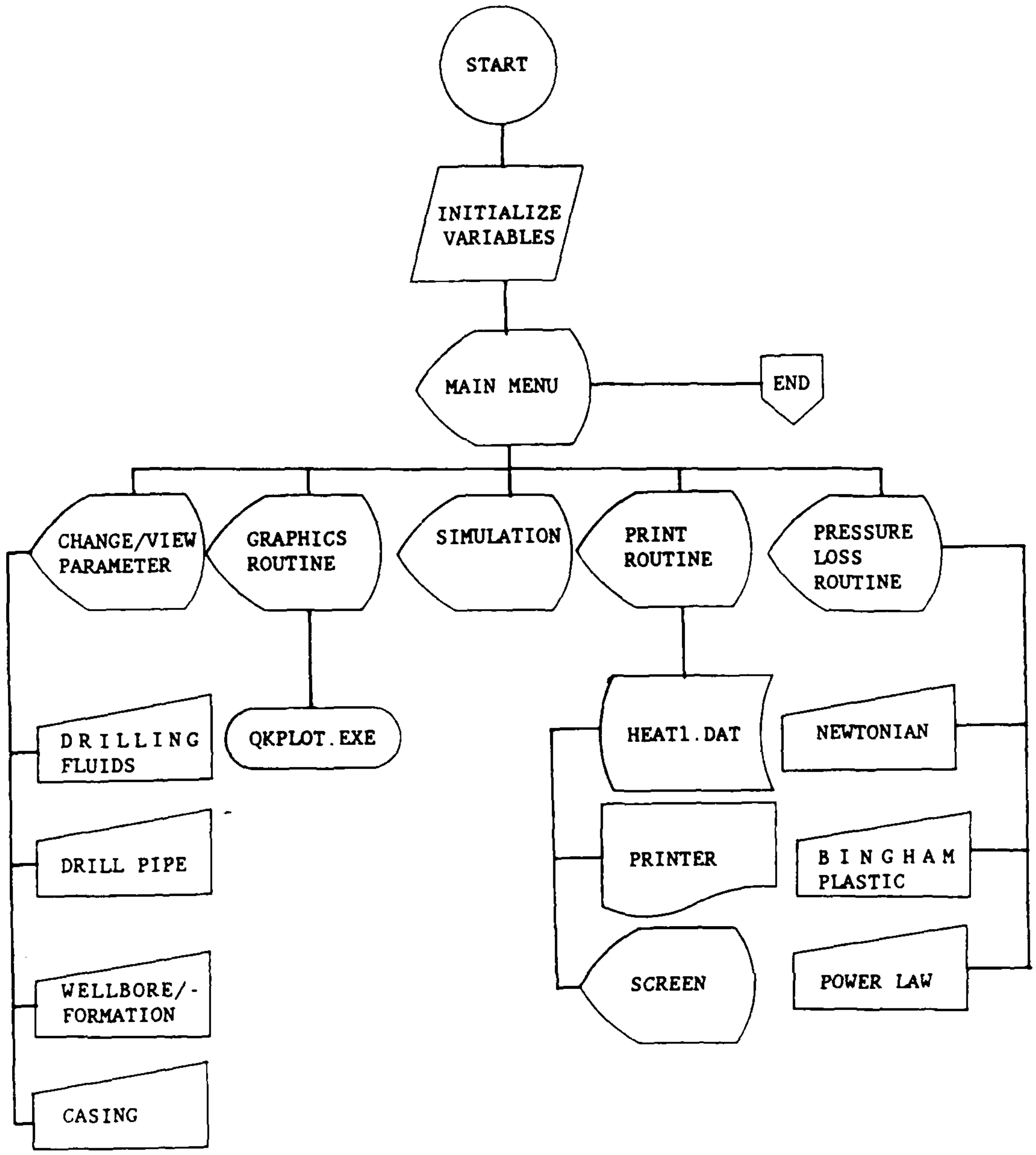


Fig. 1 - Computer program flow chart.

temperatures in a wellbore has existed since engineers first began searching for oil at greater depths, relatively little has been done to address this problem. The present trend of drilling deeper and more expensive wells requires a more accurate knowledge of the variables involved in the operation, such as temperature. In the past it has been convenient to ignore temperature gradients, largely because no practical means for estimating wellbore temperature profiles have been available.[2] Determining accurate temperature distributions in a circulating wellbore is very important for many aspects of drilling, completion, production, and injection. A few of the applications that require an understanding of the down-hole temperature history in a well include:[3]

1. Cement composition, placement, and setting time.
2. Drilling mud and annulus fluid formulation.
3. Packer design and selection.
4. Logging tool design and log interpretation.
5. Wax deposition in production tubing.
6. Corrosion in tubing and casing.
7. Thermal stresses in casing and tubing.
8. Permafrost thawing and refreezing.
9. Wellhead and production equipment design.
10. Drill bit design.
11. Elastomer and seal selection.

Of course, many other possible applications may exist. Two interesting possibilities for computer modeling are computing the

undisturbed formation temperatures from flowing temperature stream measurements and predicting abnormal pressure zones from fluid temperature changes while drilling. Analytical means must be used to model the system in question since temperature data can only be obtained by physical measurement at isolated points within the wellbore. Such methods have formed the basis for previous work in this area.

As early as 1941, scientists and engineers have studied the effect of temperature on drilling fluids and cements.[4-6] It has been well documented in the literature that downhole temperatures in a wellbore which are recorded during routine logging operations, do not measure true, static formation temperature. Due to the cooling effects of fluid circulation, recorded temperatures can be 25°F. to 70°F. lower than true, static formation temperature.[7] Many models and methods, both theoretical and empirical, designed to approximate temperature profiles in the wellbore under various conditions, have been proposed since the late 1950's.[8-21] These methods range from very simple mathematical relationships and empirical charts, which can be performed by hand calculations, to large, complex, finite-difference simulators, suitable for use on high-speed, main-frame digital computers. However, very little recent data has been gathered to verify any of these theoretical models.[14] Also, some work has been done to evaluate the effects of temperature on subsurface equipment in the wellbore.[22-28] Despite the advances in reservoir simulation, the real use and application of presently available models has been

limited to facilities with large, main-frame computers, such as training centers.

In 1967, Annis[29] published the results of an extensive study of the effects of high temperature on the flow properties of water-base drilling fluids. His investigation of the influence of time, temperatures up to 300°F, and mud composition on critical drilling fluid properties found that gel strengths tended to be more sensitive than viscosities to changes in temperature and mud composition. The gel strength of bentonitic clay drilling fluids at high temperature was not predictable from measurements made at low temperatures.

When an engineer is designing a drilling mud program or a cement slurry for setting casing, many factors must be considered, such as the density of the fluid, fluid loss control, fluid viscosity, and the deterioration of the fluid from encountering high temperatures. In the case of designing a cement job, pumping time and compressive strength must also be considered. Depending on the conditions encountered in individual wells, other factors may have to be considered.

Pumping time is a primary factor in obtaining a good cement job and, as wells are drilled to greater depths, this property becomes even more important. This is because we are experiencing ever increasing bottomhole temperatures. To design a good cement job, we must have the most accurate temperature data possible. We must design for sufficient pumping time for the cement slurry to be safely placed

in the well, but the slurry cannot be overly retarded as this will hinder the development of satisfactory compressive strength.

The prediction of wellbore temperature during circulation cannot be accomplished easily. This is because it is a complex function of wellbore geometry, geothermal gradient, circulation rate and time, fluid properties, and film heat transfer coefficients.[16] These temperature estimates which we are seeking to determine during drilling and circulation require an understanding of the thermal processes which occur in the wellbore. The information gathered may be used to predict the behavior of cement slurries, drilling muds, and drilling equipment in the severe temperatures of the downhole environment.

A further aim of this research was to use the computer simulator to simulate wellbore temperature profiles so that a thorough parametric sensitivity analysis could be carried out to determine which parameters have the most significant effect on the wellbore temperature.

STATEMENT OF THE PROBLEM

Although the simulation of temperature distributions in a circulating wellbore has many fundamental uses in modern drilling fluid and equipment design, simulation is poorly understood by engineers in the field. This is attributable to the present nature of heat and temperature simulation methods and procedures. The major disadvantage to most temperature prediction routines is that, for example, some of the methods currently available in the literature are

based on data and assumptions which do not approximate individual wells. Most of the digital computer simulators require a main frame computer to operate, and are not portable to the drill site. Therefore, an engineer on site may have temperature predictions available to him based on well design factors, but has no convenient means of obtaining real-time data on actual drilling, production, or injection operations.

Although these large-scale models are generally accurate and effective, a more flexible approach to temperature distribution simulation is needed. For a simulator to have broad applications, it should be portable, accurate, and easy to use. Highly portable simulators would permit a model to be used anywhere from the classroom to the office to the drilling rig floor. Accuracy and realism is essential to allow simulation of various drilling and producing conditions. This should be accomplished while producing representative results. Lastly, a simulator is not a genuinely useful device unless it is easy to use by those who have a need for its application. The requirements of the model should be clear and well defined, and the results from the simulation should be easy to understand and evaluate.

REVIEW OF CURRENT LITERATURE

In 1941, Farris[4] presented what is probably the earliest study of wellbore temperature. In his paper, he developed charts and special procedures for predicting the bottomhole temperatures of circulating wells based on measurements in five shallow Gulf Coast wells. Major

weaknesses associated with these charts and procedures prompted further research into a more precise method for estimating circulating temperatures. It was not until some thirteen years later that more detailed studies of cement strength and setting time were conducted. In March 1954, Swayze[5] presented the results of a committee study on the effects of high pressures and temperatures on the strength of oil well cements. In April, O'Neal and Benischek[6] presented their study of the setting time of cements as it is affected by high temperatures and pressures.

In a classic paper, Ramey[8] presented an approximate solution to the wellbore heat transmission problem involved in the injection of hot or cold fluids into injection wells. This analysis allowed for the calculation of the temperature distribution in these injection wells. His solution permitted estimates of the temperature of fluids, tubing and casing as a function of time and depth. Later, he presented a paper[30] which expanded on this derivation to give the rate of heat loss from the well to the formation.

Edwardson *et al.*[9] developed a method which has its basis in the mathematical solution of the differential equation of heat conduction. The solution of this equation is presented in a series of graphs which are used to determine formation temperature disturbances at various radii for arbitrary mud circulation conditions. This work was more concerned with temperature distribution in the formation as a result of drilling fluid circulation, and does not allow for the direct calculation of the wellbore temperature profile.

Tragesser *et al.*[10] presented a calculation technique which provided circulating temperatures, as functions of time, at varying depths in both the casing and annulus. This was an expansion of the method of Edwardson *et al.*[9] so as to allow for such variables as depth, pumping rate, hole diameter, and so forth. However, both of these techniques are based on an assumed formation temperature distribution after circulation and provided no means of calculating the wellbore temperature distribution directly.

Holmes and Swift[13] obtained a steady-state solution to the wellbore heat transfer equation for the heat transfer between the fluids in the annulus and the fluids in the drill pipe. This was combined with an approximate equation for the transient heat transfer between the fluid in the annulus and the formation. The authors state that the approximate method is adequate since the total heat transfer between the two fluids is much greater than between the annulus fluid and the formation. The low heat transfer between the annulus fluid and the formation is a result of the relatively low thermal conductivity of the formation and the film resistance to heat transfer formed at the interface of the mud and the rock. Temperatures can be calculated as a function of well depth, mud circulation rate, circulating fluid attributes, reservoir characteristics, and wellbore and drill pipe size. It is the work of Holmes and Swift[13], which is simple and readily adaptable to this study, that is the basis of the research described in this thesis.

Raymond[12] developed a method for predicting temperature distributions for both transient and pseudosteady-state conditions. He developed a generalized technique for calculating the entire temperature distribution in the system and a general method for predicting bottomhole fluid temperatures during circulation. Raymond advanced the use of the principle of superposition and the Hurst and van Everdingen functions to solve numerically for unsteady-state conditions. He insisted that the pseudosteady-state solution was adequate for all applications.[2]

In 1977, Fertl and Wichmann[7] introduced a simple and rapidly applied technique for analyzing maximum bottomhole temperatures, which are recorded during well logging operations, to determine static formation temperature. The method requires the use of a maximum recording thermometer on each logging run, plus information concerning circulating time and time that the logging tool was last on the bottom of the borehole.

Most recent research has dealt with means of solving unsteady state equations formulated by Raymond, or variations on these, using finite difference techniques.[2,3,15-21] Although the earlier methods are simple and easy to apply, they are not particularly accurate. The more recent computer models involve solving the finite difference equations describing the heat transfer by iterative methods. Such methods have the obvious disadvantages of long solution times and the simultaneous problems of stability and accuracy.

In 1968, Keller and Couch[11] studied the damage to production wells caused by the high temperatures associated with in-situ combustion projects. Injection of water down the annulus of hot wells has been successfully utilized for cooling and prolonging the life of such wells. They developed a mathematical model that was acceptable for predicting the effectiveness of cooling water in a particular application.

Keller *et al.*[15] developed a model which described the two-dimensional transient heat transfer in and around a wellbore. Their results demonstrated that the use of steady-state solutions previously published gave good estimates of the circulating mud temperatures. The transient solution that was presented in their paper was more suited for matching temperature logs.

Sump and Williams[16] presented an improved model which they stated was more accurate than the use of API correlations or other numerical techniques. Their model was based on an existing mathematical model of the wellbore and the formation near the wellbore. This existing model was improved by altering the film heat transfer coefficients and the formation thermal conductivity. The coefficients were modified to simultaneously minimize the difference between measured and predicted temperatures for six wells.

As computer models have become more sophisticated, numerous authors have presented simulators which model even more complex well conditions. An excellent example of this is the study by Oster and Scheffler[17] which described their model for determining the

temperature distribution in a circulating drilling fluid when aquifers are present in the formation. The depth of the aquifer relative to the well depth was shown to be an important parameter.

As computers have become faster and more able to solve increasingly complex problems, temperature distribution simulators have become more complicated. In 1980, Wooley[3] presented a complex model for predicting downhole wellbore temperatures in flowing of shut-in fluid streams, in casing and cement, and in formations. Flowing options include injection/production, forward/reverse circulation, and drilling.

In 1981, Cline[19] formulated a mathematical model of the temperature distribution inside a circulating wellbore. He assumed that the heat transfer processes between the formation and the circulating fluid in the wellbore occur in a pseudo-steady manner. A closed form solution to the counterflow energy equations was developed in a manner which allows for arbitrary temperature distributions in the formation.

Marshall and Bentsen[2] developed a computer model which uses a direct solution technique to solve the finite difference equations describing transient heat transfer in the wellbore. The authors claim that their solution technique is considerably more efficient than those used in earlier studies.

In 1984, Duda[20] presented computer calculations of wellbore transient temperatures, using the geothermal wellbore thermal simulator code GEOTEMP2. These calculations were made on four well

models. Also in 1984, Corre *et al.*[21] developed a computer model which could be used for determining temperature profiles in and around a wellbore during drilling phases. This model has been used to design mud and drilling programs to ensure better hole stability.

While various authors were working to more accurately model and predict downhole circulating mud temperature distributions, other authors were studying the effects of temperature on subsurface equipment.

Leutwyler and Bigelow[22] made a detailed study of the effects of temperature change on tubing, casing, and associated downhole equipment as a result of injection or production of fluids at temperatures substantially higher than the surrounding formations. They presented a method for making an approximation of the casing temperature and for analyzing the buckling criteria.

In 1966, Leutwyler provided an excellent review of much of the information leading to the prediction of heat losses from tubing string to the wellbore. He also reviewed the line source solution to the diffusivity equation and examined some of the application criteria in light of the unsteady-state conditions.

Dase and Heyt[24] studied the thermal protection of wellbore casings. Their analytical study of heat transfer through the wellbore during hot fluid stimulation was to determine the effect of a concentric radiation shield and forced convection gas flow as methods for the reduction of casing temperature and associated thermal stress which may lead to failure.

DISCUSSION OF THE MODEL

As stated earlier, the primary objective of this research was to design a totally "user friendly" computer program to assist the drilling engineer or the production engineer to more accurately model the temperature and heat transfer processes that are occurring in the circulating wellbore. During the course of developing this program, the author was able to include pressure loss calculations. The simulator should be flexible, easy to use, provide simple, effective output which is easy to use, and require a minimum amount of data and time to operate. However, the quality and accuracy of the results should not be compromised. To make the model flexible, it is designed for use on a personal computer. This operating environment encourages the use of floppy disks and minimal program size. The key advantage to the use of floppy disks is their portability. Because of the capacity of floppy disks and the variable memory sizes of personal computers, the simulator in question had to have reasonable memory requirements. The final version of this heat transfer and temperature gradient simulator has a memory requirement of less than 50 kilobytes and can be operated on a machine having 256 kilobytes of RAM memory.

To enhance the practical nature of the model, it was vital to create a set of subroutines that acted as a complete package. This suggests that the simulator be "user friendly", i.e., interactive, self explanatory, flexible, and easy to use. To realize these objectives, it was necessary to employ a liberal amount of on-screen graphics and menus. The program HEAT.BAS creates the data file which

describes the circulating well and the heat and temperature processes within it. The data are logically separated by category and are presented as "pages" of information. Each "page" describes the variables, their appropriate units, and the default values that are built into the main program. Also, each "page" has the current date and time available for the user. Menus let the program user move quickly between these "pages".

In order to use this program, the personal computer should also have the compiler QUICKBASIC.EXE in the RAM. Once this is accomplished, the program HEAT.BAS can be loaded into QUICK.BASIC and the heat transfer program can be run. Upon executing HEAT.BAS, the first "page" of information that appears on the terminal screen is the title block with the name of the program and the name of the author, as illustrated in Fig. 2. The user is prompted to press any key to move to the next "page".

Having pressed a key, the second "page" appears and, once the beep sounds, the "Program Master Menu" is ready for use. This "page" is shown at Fig. 3. On this menu, the user can select from six options. These options include:

(1) Quit (exit the program),

(2) To change/view program parameters,

(3) To execute the graphics routine,

(4) To print out a table of data,

(5) To run the simulation,

(6) To determine pressure losses.

```
ZDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDD?
3                                                  3
3     A PC Simulation of Heat Transfer and         3
3                                                  3
3        Temperature Distribution in               3
3                                                  3
3          a Circulating Wellbore                  3
3                                                  3
3                   by                             3
3                                                  3
3              Robert D. Pierce                    3
3                                                  3
@DDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDDY


        Press any key to continue
```

Fig. 2 - Introductory menu of program.

```
                          Program Master Menu

                              Select One

xxxxxxxxxxxxxxxxxx 11-03-1987 xxx 11:28:57 xxxxxxxxxxxxxxxxxxx

(A) QUIT      (B)........ To Change/View Program Parameters

              (C).........To Execute Graphics Routine

              (D).........To Print Out Table

              (E).........To Run Simulation

              (F).........To Determine Pressure Losses

          To continue, press a key.
```

Fig. 3 - Program master menu.

Should the user select the "change/view program parameters" option, that menu will be the next on the terminal screen. Fig. 4 shows an example of this menu. On this menu the user again has several options. These include:

(1) Quit (exit the program),

(2) To change drilling fluid parameters,

(3) To change drill pipe parameters,

(4) To change wellbore/formation parameters,

(5) To change casing parameters,

(6) To return to the main program menu.

Each of these menus will then take the user to the appropriate menu to change and/or view the program parameters. If the user wishes to change/view the drilling fluid parameters, he would press the appropriate key and the menu would be revealed on the terminal (Fig. 5). The drilling fluid parameters built into the program include thermal conductivity of the mud, inlet mud temperature, mud density, flow rate, viscosity of the mud, and specific heat of the mud. Also, there is an option to return to the drilling parameters menu.

If the user had desired to change/view one of the other parameter menus, a similar operation could be conducted. Each of these other menus would, again, lead the user through the required entries, and back to the main program menu. Figs. 6 through 8 show these menus. Once the user is satisfied with the values of each of the parameters, other operations can be performed.

```
                Parameter Change/View Menus

                       Select One

              11-03-1987     11:19:22

(A) QUIT       (B)........To Change Drilling Fluid Parameters

               (C)........To Change Drill Pipe Parameters

               (D)........To Change Wellbore/Formation Parameters

               (E)........To Change Casing Parameters

               (M)........To Return To Main Menu

          To continue, press a key.
```

Fig. 4 - Change/view parameters menu.

Drilling Fluid Parameters

Select One

11-03-1987 ... 11:29:29

(A) QUIT

(B) Thermal Conductivity of Mud = 1 Btu/(hr*ft*deg F)

(C) Initial Inlet Mud Temperature = 75 deg F

(D) Density of Mud = 10 lb/gal

(E) Flow Rate = 210 Gal/min

(F) Absolute Viscosity of Mud = 11 lb/(ft*hr) (4.54 [illegible]

(G) Specific heat of Mud = .4 Btu/(lb*deg F)

(M) Return to Parameters Menu

To continue, press a key.

Fig. 5 - Drilling fluid parameters menu.

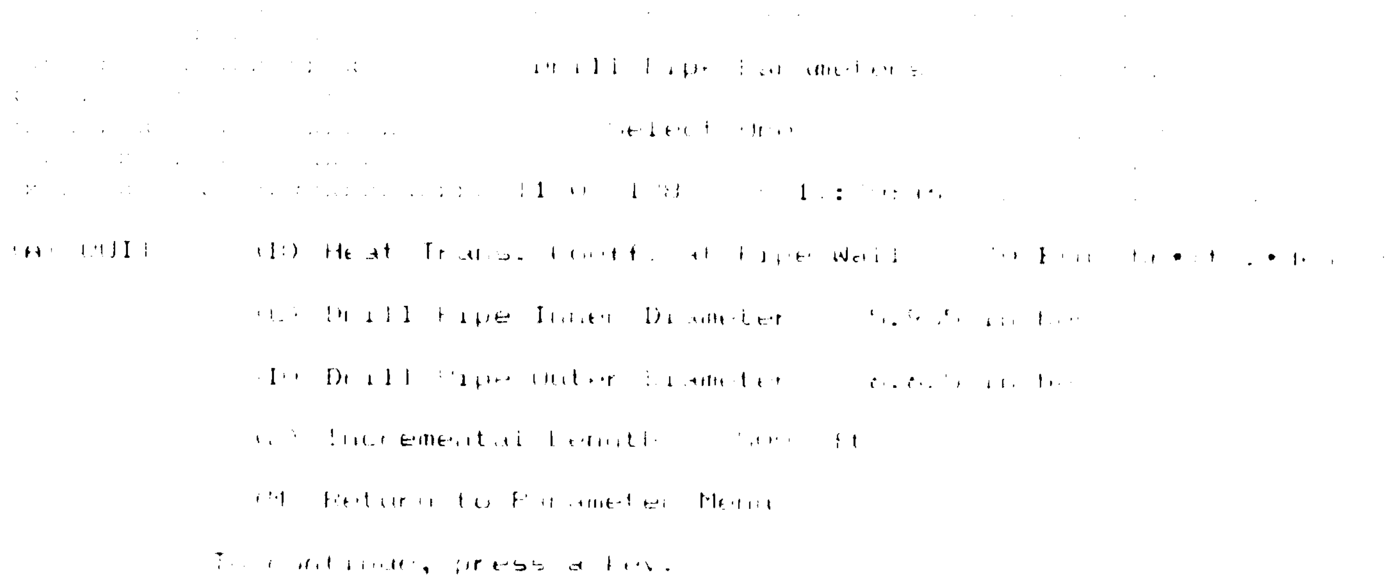


Fig. 6 - Drill pipe parameters menu.

Fig. 7 - Wellbore/formation parameters menu

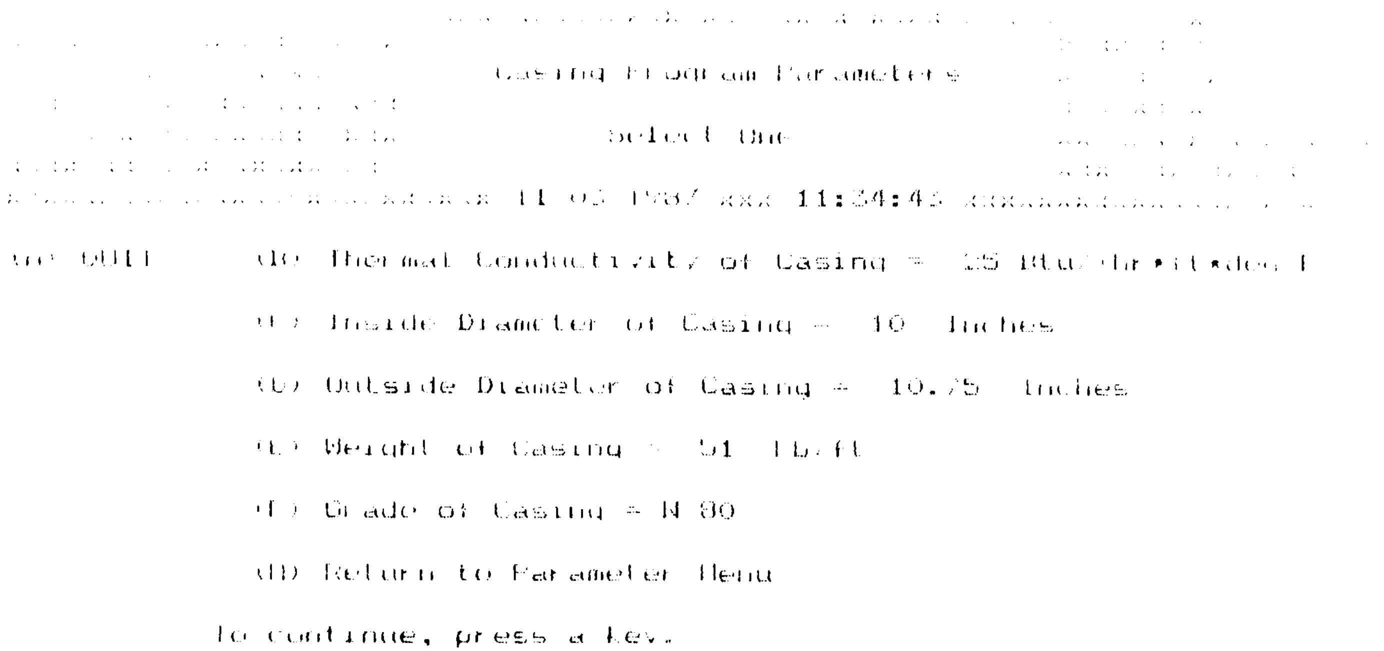


Fig. 8 - Casing parameters menu.

The quickest and easiest way to understand data is by visual inspection, either in the form of pictures or graphical plots. Both of these method are used in the heat transfer model. Finally, the results of the simulation can be saved on a disk and/or routed to a printer. With these options, the presentation and understanding of the simulation can be maximized.

MODEL FORMULATION

The mathematical system of equations used in this simulator are from the papers by Ramey[8] and Holmes and Swift[13]. Ramey's solution method was further refined and amplified by Horne and Shinohara[18]. Incropera and DeWitt[25] and Wilhite's paper[28] were used as the basis for the calculation of the over-all heat transfer coefficients, U.

Generally, there are three components of wellbore thermal simulators: flowing stream, well completion, and formation. The relative importance of each component depends on the particular application and the desired result. For predicting surface temperatures in high-rate production wells, formation calculation is much less important than flowing stream calculation[3]. This is particularly applicable in geothermal wells. On the other hand, for predicting permafrost thawing around an arctic well the flowing stream is less important than the formation.

Circulation of fluid during the drilling operation is represented schematically in Fig. 9. The process of circulation has three distinct phases[12]: (1) fluid enters the drill pipe at the surface and passes down the drill pipe; (2) fluid exits the drill pipe through the

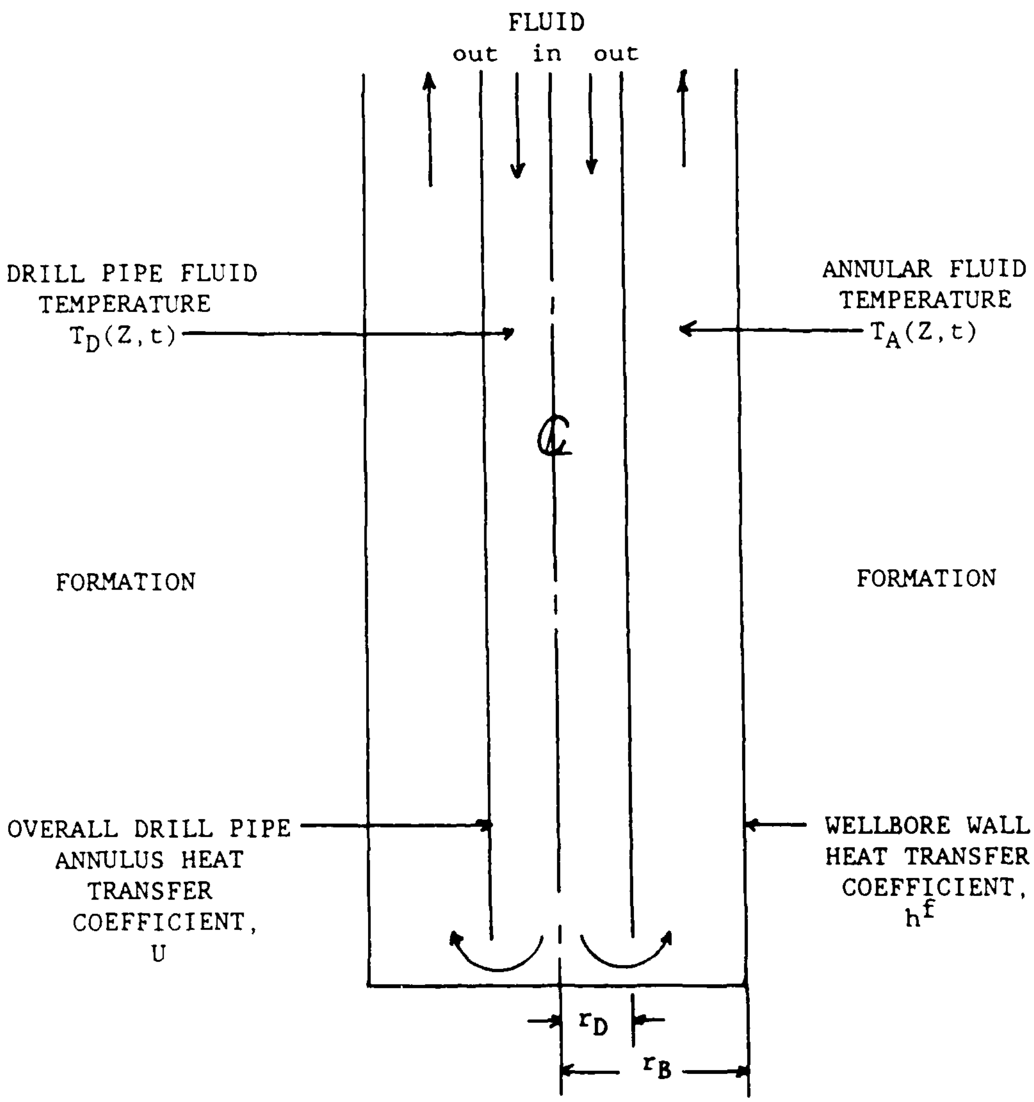


Fig. 9 - Schematic of circulating fluid system.

bit and enters the annulus at the bottom of the wellbore; and (3) fluid passes up the annulus and exits the annulus at the surface. To simulate the thermal behavior in the system, each of the phases of circulation must be described mathematically.

In Phase 1, the fluid enters the drill string at a specified temperature, T_{Do}. As the fluid passes down the pipe, its temperature is determined by the rate of heat convection down the drill pipe, the rate of heat exchange between the drill pipe and the annulus, and time. Phase 2 of the circulating operation simply requires that the fluid temperature at the exit of the drill string be the same as the fluid temperature at the entrance of the annulus; i.e., $T_D(Z,t) = T_A(Z,t)$[12]. Therefore in Phase 3, the fluid enters the annulus at $T_D(Z,t)$. As the fluid flows up the annulus, its temperature is determined by the rate of heat convection up the annulus, the rate of heat exchange between the annulus and the drill pipe, the rate of heat exchange between the formation adjacent to the annulus and the fluid in the annulus, and time. These rates of heat exchange and the time dependency of the mud temperature are described by well known heat-flow equations.[25] Consequently, as shown in Appendix A, the temperature profiles in the drill pipe, annulus, and formation can be obtained by solving Eqs. 1 through 3 with the added condition as stipulated in Eq. 4, once appropriate initial and boundary conditions are specified.

Eq. 1 describes the heat flow within the drill string. The terms on the left hand side represent the vertical and radial convective

heat transfer, respectively. The terms on the right represent the accumulation of energy within the drill string.

$$A_D \rho v_D C_p \frac{\delta T_D(Z,t)}{\delta Z} + 2\pi r_D U[T_D(Z,t) - T_A(Z,t)] = -\rho A_D C_p \frac{\delta T_D(Z,t)}{\delta t} \quad \text{. . . . .} \quad (1)$$

The energy balance in the flowing annulus is represented by Eq. 2. The three terms on the left hand side represent the vertical convective heat transfer within the fluid, radial convection between the drilling fluid and the drill pipe wall, and radial convection between the drilling fluid and the casing or formation, respectively. Heat accumulation is accounted for by the term on the right.

$$A_A \rho v_A C_p \frac{\delta T_A(Z,t)}{\delta Z} + 2\pi r_D U[T_D(Z,t) - T_A(Z,t)] + 2\pi r_B h_f[T_f(r_w,Z,t) - T_A(Z,t)] = \rho A_D C_p \frac{\delta T_A(Z,t)}{\delta t} \quad \text{. . . . .} \quad (2)$$

Eq. 3 is a two-dimensional thermal conductivity equation representing heat flow in the formation. The terms on the right account for the vertical and radial conduction, and the term on the left accounts for the heat accumulation.

$$\frac{\delta T_f(r_w,Z,t)}{\delta t} = \frac{k_f}{\rho_f C_{pf}} \frac{1}{r} \frac{\delta}{\delta r} \left[r \frac{\delta T_f(r_w,Z,t)}{\delta r} \right] \quad \text{. . . . .} \quad (3)$$

One boundary condition for Eq. 3 requires that the flux out of the formation be the same as the flux into the annulus and is given by Eq. 4. Since at large values of r the geothermal temperature is undisturbed, the second boundary condition is: $T_f(r \to \infty, Z, t) = T_s + GZ$. Thus,

$$2\pi r_B h_f [T_f(Z,t) - T_A(Z,t)] = 2\pi r_B k_f \left[\frac{\delta T_f(r_w, Z, t)}{\delta r}\right]_{r = r_B} \quad \text{. . . . .} \quad (4)$$

To obtain the energy balances above which describe the thermal behavior of the wellbore certain assumptions about the heat transfer mechanisms and flow behavior are required[2]:

1. Flow is steady state and fully developed.

2. Flow is turbulent in the drill pipe and across the drill bit, and laminar in the annulus.

3. Heat transfer within the drilling fluid is by axial convection. Axial conduction is neglected.

4. The radial temperature gradient within the drilling fluid may be neglected.

5. Heat generation by viscous dissipation within the fluid may be neglected.

6. Fluid properties such as density, thermal conductivity, and specific heat are independent of temperature.

HOLMES AND SWIFT[13] MODEL

The equations in this portion of the simulator are based on the assumptions that the heat transfer between the fluid in the annulus and the formation can be approximated by steady-state linear heat transfer. The work of Edwardson *et al.*[9] has shown that the temperature is relatively constant at any point sufficiently removed from the drill bit. This effect shows that the steady-state assumption appears to be a close enough approximation of this phenomenon. Other simplifying assumptions are that the heat generated by the drill bit is negligible and that a linear geothermal profile exists.

The development of the model is depicted in Fig. 10. A slab of thickness *dx* is used, assuming heat transfer in the radial direction and no significant longitudinal conduction. The heat accumulation of the fluid in the annulus between depth x and x + dx is given by

$$\dot{Q}_{ax} - \dot{Q}_{a(x+dx)} = mc_p[T_{Ax} - T_{A(x+dx)}] \qquad (5)$$

and the steady-state approximation of the heat transferred between the annular fluid and the formation is given by

$$\Phi = 2\pi r_w U(T_A - T_f)dx \qquad (6)$$

The heat balance across the drill pipe is represented by

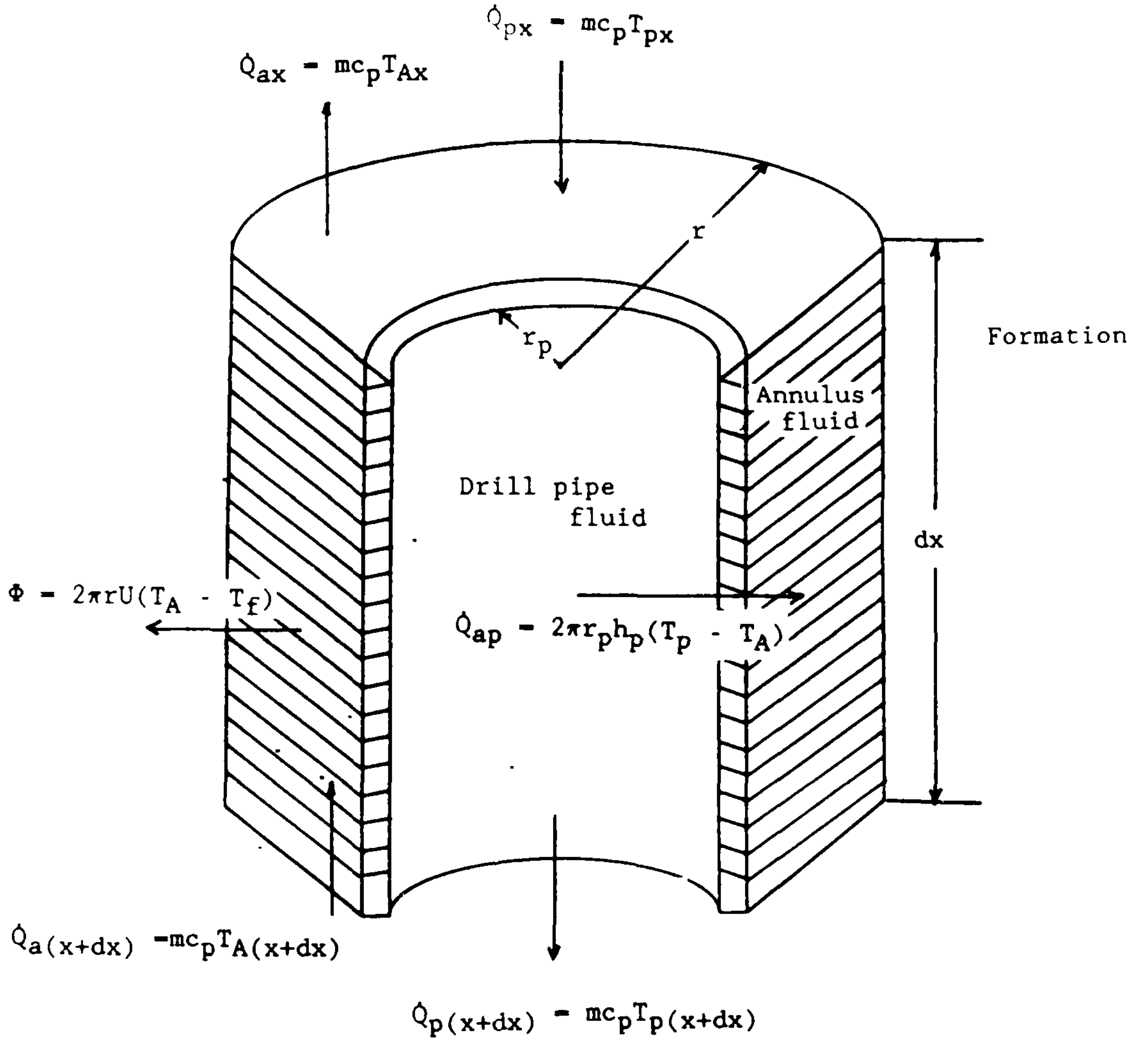


Fig. 10 - Differential fluid element used to derive the Holmes and Swift[13] model.

$$\dot{Q}_{ap} = 2\pi r_D h_p (T_p - T_A) dx \quad \ldots \quad (7)$$

Combining these equations yields the over-all heat transfer through the annulus,

$$mc_p \frac{dT_A}{dx} + 2\pi r_D h_p (T_p - T_A) = 2\pi r_w U (T_A - T_f) \quad \ldots \quad (8)$$

The formation temperature may be approximated as:

$$T_f = T_s + GZ \quad \ldots \quad (9)$$

Substituting Eq. 9 into the over-all heat balance for the annulus produces the heat balance for the element across the annulus fluid:

$$mc_p \frac{dT_A}{dx} + 2\pi r_D h_p (T_p - T_A) = 2\pi r_w U (T_A - T_s - GZ) \quad \ldots \quad (10)$$

A similar development for the fluid in the drillstem gives the following heat balance:

$$mc_p \frac{dT_p}{dx} = 2\pi r_D h_p (T_p - T_A) \quad \ldots \quad (11)$$

These are the equations of the linear heat transfer model of Holmes and Swift[13]. The equations are then integrated into their

applicable form. These are, for the temperature of the mud in the drillstem,

$$T_p = K_1 e^{C_1 Z} + K_2 e^{C_2 Z} + GZ + T_s - GA \qquad (12)$$

and for the temperature of the mud in the annulus,

$$T_a = K_1 C_3 e^{C_1 Z} + K_2 C_4 e^{C_2 Z} + GZ + T_s \qquad (13)$$

where

$$C_1 = (B/2A)[1 + (1 + 4/B)^{0.5}] \qquad (14)$$

$$C_2 = (B/2A)[1 - (1 + 4/B)^{0.5}] \qquad (15)$$

$$C_3 = 1 + B/2[1 + (1 + 4/B)^{0.5}] \qquad (16)$$

$$C_4 = 1 + B/2[1 - (1 + 4/B)^{0.5}] \qquad (17)$$

$$A = mc_p/2\pi r_D h_p \qquad (18)$$

$$B = r_w U/r_D h_p \qquad (19)$$

These equations when applied with the proper boundary conditions

represent the analytical solution of the mud temperature profiles for the fluid in the drillstem and annulus.

Derivation of Circulating Temperature Equations

Since the annular and drill pipe mud temperatures are equal at the bottom of the wellbore, the following boundary conditions may be applied to obtain the bottomhole temperature[13].

Boundary Condition 1 at $x = 0$; $T_D = T_{Do}$

Boundary Condition 2 at $x = L$; $T_{Hp} = T_{Ha}$

For these boundary conditions the following integration constants are obtained:

$$K_1 = T_{Do} - K_2 - T_s + GA \quad \ldots \quad (20)$$

$$K_2 = \frac{GA - [T_{Do} - T_s + GA]e^{C_1 L}(1 - C_3)}{e^{C_2 L}(1 - C_4) - e^{C_1 L}(1 - C_3)} \quad \ldots \quad (21)$$

These constants of integration are applied to Eqs. 12 and 13 in order to calculate the temperature at any point in the well during circulation.

RAMEY[8] MODEL

The classic study performed by Ramey on wellbore heat transmission derived the temperature distribution in a well used for injecting hot fluids.[18] Ramey later expanded on this to give the rate of heat loss from the well to the formation.[30] However, by assuming that the fluid remains at its inflow temperature, Ramey's analysis effectively gave the heat loss at infinite fluid flow rate -- in other words, the maximum possible heat loss rate.[18] A paper presented by Horne and Shinohara[18] reexamined this problem for finite fluid flow and determines the heat loss rate as a function of fluid properties and fluid flow rate. Their paper presents results for both producing and injection wells, which is valuable when analyzing geothermal wells. It is assumed the only single-phase fluids are flowing in the wellbore. For single-phase flow, the formulation permits direct calculation of wellbore heat loss with various production and injection conditions.[18] Derivation of Ramey's wellbore heat transmission solution is found in Appendix B.[31-34]

Injection

As in Fig. 11, consider a heat balance in the radial direction on a section of a well with height *dz*, losing heat at rate *dq* from the casing to the formation. Then,

$$\frac{dq}{dz} = \frac{2\pi k_f r_D U}{k_f + r_D U f(t)} (T_D - T_f) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (22)$$

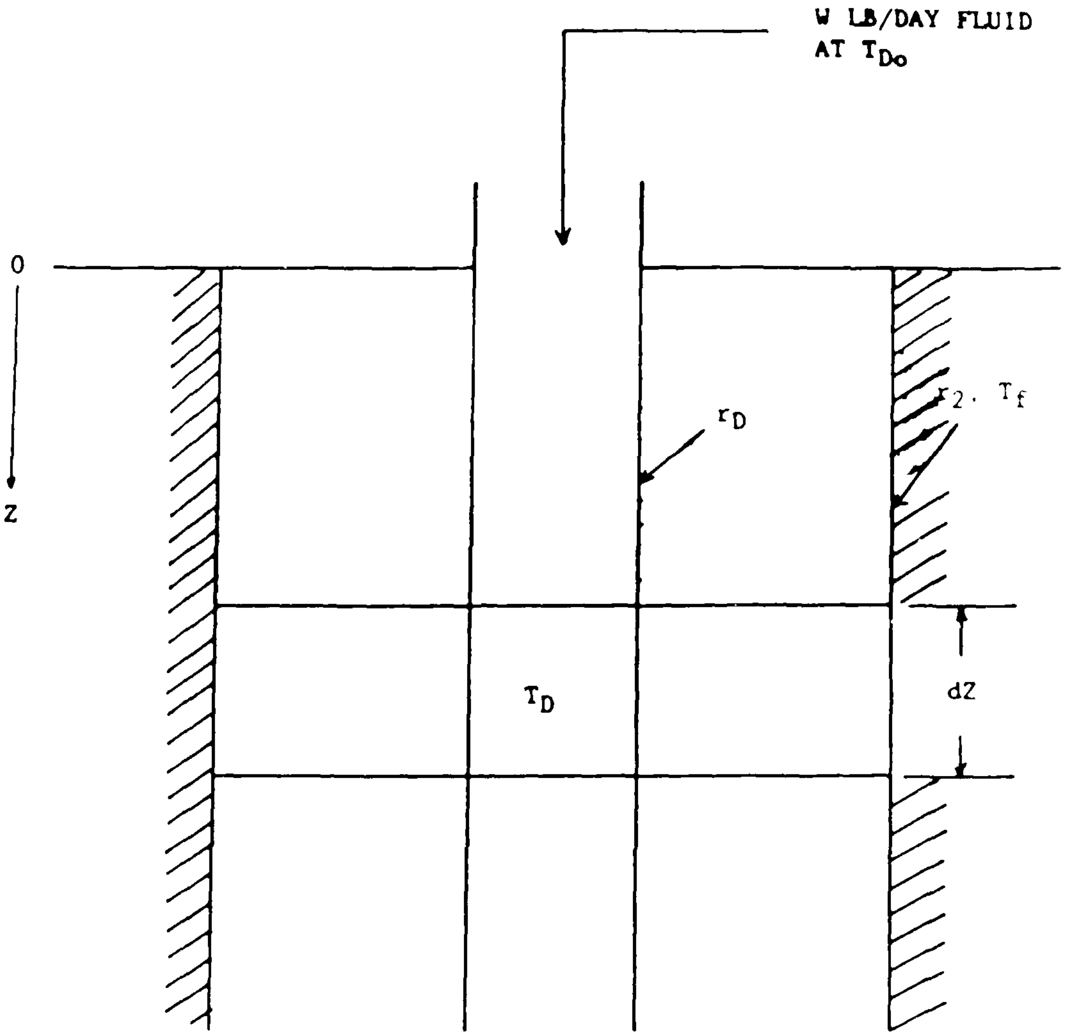


Fig. 11 - Schematic of wellbore heat problem.

For long periods of time, f(t) can be approximated as

$$f(t) = -\ln \frac{r_2}{2\sqrt{\alpha t}} - 0.290 + O(r_2/4\alpha t) \quad \text{. . . . .} \quad (23)$$

Ramey's Eq. 23 is adequate for use for periods of time greater than one week. For time periods less than one week, Ramey provided a graphical solution. However, in order to further refine the computer model to more efficiently use Ramey's graph of the function f(t) versus $\log_{10} (\alpha t/r_2{}^2)$, the curve representing constant temperature at $r = r_2$, cylindrical source, was digitized using the computer program, DIGIT, which is available on the Petroleum Engineering Department's PRIME computer. Once the curve was digitized, the data were then analyzed by the PRIME's least squares curve fitting program, CURVIT. It was determined that the data provided by Ramey's curve fit a third order power curve (log-log) almost exactly. Fig. 12 is a plot of the third order power curve generated by the computer versus the actual data provided by Ramey. The curve in question is modeled by the equation

$$f(t) = 0.0018302 (\ln x)^3 - 0.045016 (\ln x)^2 + 0.49045 (\ln x) - 0.44056 \quad \text{. . . . .} \quad (24)$$

Performing an over-all heat balance on the well and considering

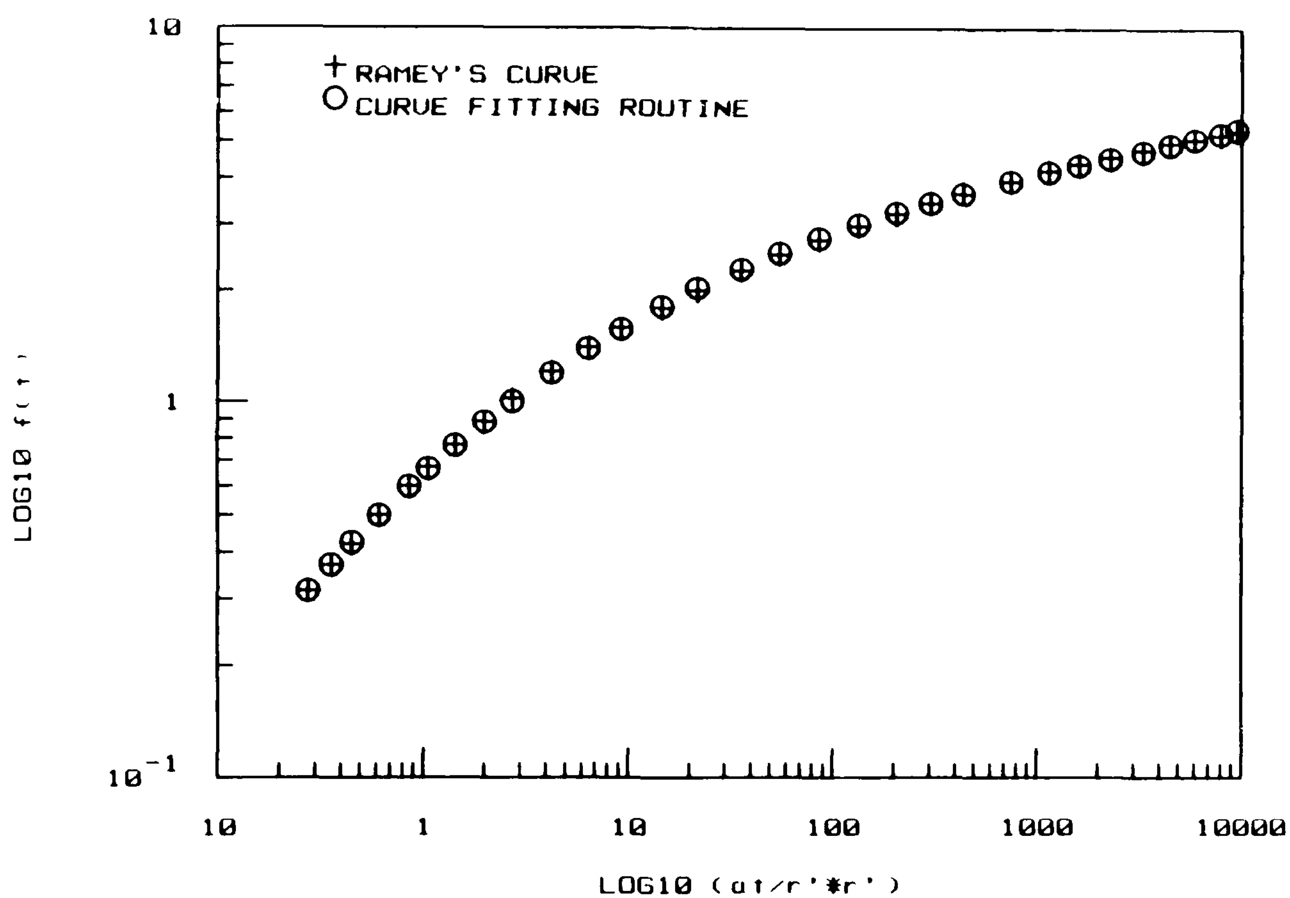


Fig. 12 - Curve fitting plot for Ramey's time function.

the changing temperature of the fluid as it flows in the tubing, T_p can be estimated as

$$T_p = GZ + T_s - GA + (T_{Do} - T_s + GA)e^{-Z/A} \quad (25)$$

where $GZ + T_s$ is T_f, the formation temperature (assuming linear geothermal gradient), T_s is the surface temperature, and Z is measured downward. T_{Do} is the injection temperature. A is a group of variables which Ramey defined as

$$A(t) = \frac{wc_p[k_f + Uf(t)]}{2\pi k_f r_D U} \quad (26)$$

Integrating Eq. 22 (with respect to depth Z) and substituting $T_D = T_{Do}$, Ramey[30] obtained

$$q_\infty = \frac{2\pi r_D U k_f}{k_f + r_D U f(t)} \left[(T_{Do} - T_s)L - \frac{aL^2}{2} \right] \quad (27)$$

as the total heat loss rate from a well of total depth L. However, by substituting the actual value of T_D from Eq. 25,

$$q = -wc_p \left[GL - (T_{Do} + GA - T_s)(1 - e^{-L/A}) \right] \quad (28)$$

or alternatively,

$$q = wc_p(T_{Do} - T_D) \quad \ldots \quad (29)$$

Comparing q_∞ [the total heat loss rate for a well with infinite flow rate (Eq. 27)] with q [the total heat loss for a well with flow rate w (Eq. 28)], q is found to be a function of both w and c_p, whereas q_∞ is independent of both the fluid that flows in the wellbore and the rate at which it flows.

Production

With a well producing hot fluids, Eqs. 25, 27, and 28 can be used by replacing T_s with T_{Do}. With a geothermal well producing hot fluid without tubing, the temperature in the well as a function of height y above the producing depth can be given as

$$T_D = (T_{Do} - Gy) + GA(1 - e^{-y/A}) \quad \ldots \quad (30)$$

Here, the temperature of the earth is T_{Do} - Gy and, since there is no tubing, U is infinite; therefore,

$$A = \frac{wc_p f(t)}{2\pi k_f} \quad \ldots \quad (31)$$

Then, the maximum total heat flow rate from a well of depth L would be

$$q_\infty = \frac{\pi k_f G L^2}{f(t)} \quad \ldots \quad (32)$$

whereas the actual total heat flow rate would be

$$q = G w c_p \left[L + A(e^{-L/A} - 1) \right] \quad \ldots \quad (33)$$

Clearly, for large flow rates, the heat loss rate approaches that for infinite flow[18]. If the exponential function in Eq. 33 (or Eq. 28) is expanded in a polynomial series, the significance of other governing parameters can be evaluated[18]. Substituting

$$e^{-L/A} = 1 - \frac{L}{A} + \frac{L^2}{2A^2} - \frac{L^3}{6A^3} \ldots ,$$

then,

$$q = \frac{\pi H k_f L^2}{f(t)} - \frac{w c_p G L^3}{6A^2} + \sum_{n=4}^{\infty} (-1)^n \frac{w c_p G L^n}{n! A^{n-1}} \quad \ldots \quad (34)$$

Comparing this with Eq. 32 for q_∞, the difference between q and q_∞ (1) is always negative, $q < q_\infty$; (2) increases with geothermal gradient, a; (3) increases rapidly with depth, L; (4) decreases with increasing

flow rate, w (since A is a linear function of w and c_p); (5) decreases with increasing specific heat, c_p; for example, a steam well will lose less heat than a hot water well; and (6) increases with time, t [since f(t) increases with t and A decreases][18].

Thus, the traditionally used formulas for heat loss from a well carrying hot fluid in single-phase flow are shown to overestimate heat loss severely, particularly in deep wells with moderate-to-low flow rates of low specific-heat fluids. This would be important in steam injection, where the quantity of steam required would be overestimated, or when flow testing a geothermal well, where down-hole enthalpies and steam quality are calculated by considering wellhead conditions and wellbore heat loss. A more complete discussion of the over-all heat transfer coefficient, U, can be found in Appendix D.

PRESSURE LOSS CALCULATIONS

The basis of any simulation of the drilling process is the drilling fluid or mud. The drilling fluid serves a variety of purposes such as cooling the bit, transporting the cuttings to the surface, and controlling subsurfac pressures. Drilling fluids have progressed from little more than clay suspensions to highly complex substances both rheologically and chemically. This problem is further aggravated by the fact that the rheology and chemical make up can change greatly, even during the course of drilling a single well.

Knowing what displacement pressure and flow rate will maintain a drilling fluid or cement slurry in turbulent or plug flow in the wellbore annulus is essential in the design of a drilling hydraulics program or primary cement job. The frictional pressure loss term in the pressure balance equation is the most difficult to evaluate[35]. The pressure balance equation in question is

$$p_1 + 0.052\rho(D_2 - D_1) - 8.074\text{x}10^{-4}\rho(\bar{v}_2^{\,2} - \bar{v}_1^{\,2}) + \Delta p_p - \Delta p_f = p_2 \quad \ldots\ldots \quad (35)$$

Fluids in plug or turbulent flow exert a uniform displacement force against the mud in the wellbore annulus[36]. In laminar flow, cement has a parabolic or "bullet-shaped" velocity profile across the area of flow. This results in the cement "jetting" through the drilling fluid[36]. Incomplete mud removal can result in poor cement bonding, zone communication, and ineffective stimulation treatments.

A mathematical or empirical fluid model describes the flow behavior of a fluid by expressing some type of relationship between shear rate and shear stress. This model of the viscous forces present in a drilling fluid is required for the development of frictional pressure loss equations. For a Newtonian fluid, the ratio of the shear stress to the shear rate is a constant. However, for non-Newtonian fluids the relationship between shear stress and shear rate is more complicated. Most drilling fluids are non-Newtonian in nature. As of the date of this paper, a generalized relationship for all non-Newtonian fluids has not been found[37]. Instead, several models have been proposed to describe the behavior of various ideal non-Newtonian fluids.

For this model, three different rheological models were chosen because of their general use in the drilling industry. The three most commonly used and understood models are the Newtonian, Bingham Plastic, and the Ostwald-deWaele Pseudoplastic (Power Law). Appendix C contains a complete discussion of the equations used for pressure loss calculations for each of the three most commonly accepted fluid rheologies.

NEWTONIAN FLUID MODEL

The Newtonian fluid model is defined by the relationship

$$\tau = \mu \gamma \quad \ldots \quad (36)$$

At conditions of constant temperature and pressure, the shear rate and the shear stress are directly proportional. The constant of proportionality, μ, is called the absolute viscosity. Fig. 13 shows the flow curves of Newtonian fluids. Note that the curves are straight lines which pass through the origin, and that the slopes of the lines are μ, the absolute viscosity. As shown in Fig. 13, the thicker the consistency of the fluid, the larger is the magnitude of the slope.

Water and several pure organic liquids are Newtonian fluids in nature[37]. Drilling fluids rarely behave as Newtonian fluids. Because Newtonian fluids behave in a relatively simple manner, they provide an ideal fluid for fluid flow experiments[38].

Non-Newtonian Fluid Models

The ratio of the shear rate to the shear stress of a non-Newtonian fluid is not constant. This is true for most drilling fluids. The two most widely accepted mathematical models for describing non-Newtonian drilling fluids are called the Bingham Plastic model and the Ostwald - deWaele power law model. Hence it is generally accepted that drilling fluids are typified by one of these two models.

Bingham Plastic Model

The Bingham Plastic model is defined by the relationship

$$\tau = \tau_o + \mu_\infty \gamma \quad \ldots \quad (37)$$

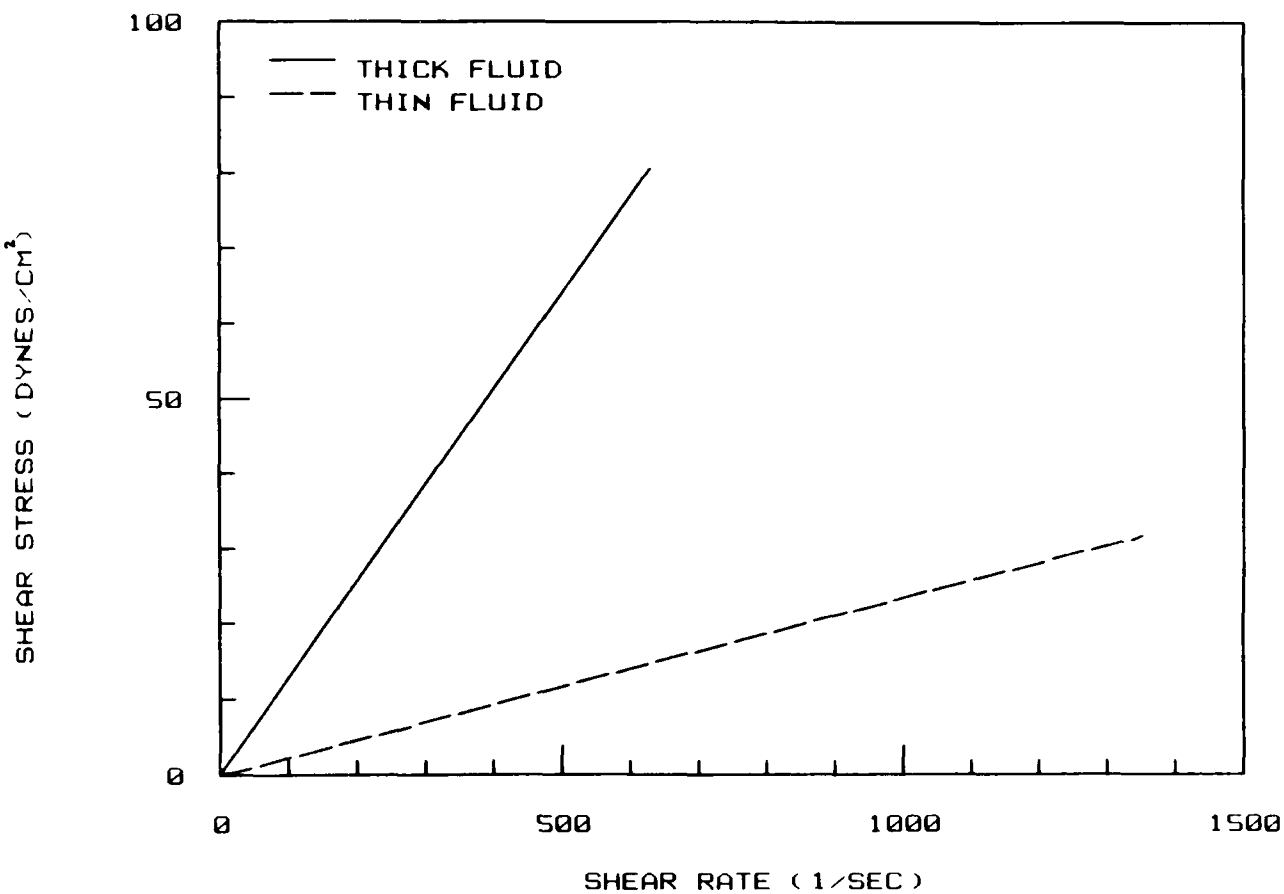


Fig. 13 - Example of the relationship between shear stress and shear rate for a Newtonian fluid.

As can be seen in Fig. 14, the Bingham fluid differs from a Newtonian fluid most notably by the presence of a yield stress, most commonly called the "yield point"[37]. The yield stress is a measure of the electrical attractive force in the drilling mud under flowing conditions. The Bingham Plastic model assumes that a fluid behaves as an elastic solid up to the yield stress[39]. Then it behaves as a Newtonian fluid above this point. No bulk movement of the fluid occurs until the applied stress exceeds the yield stress. Once the yield stress is exceeded, equal increments of shear stress produce equal increments of shear rate. Forces less than the yield stress produce a deformation, usually ignored because it is so small, but cause no discernable flow. Bingham Plastic - type fluids flowing through a tube are characterized by an inner plug moving in a fluid ring. Attempts to fit Bingham Plastic fluids with a power law - type model result in extremely low values for the Power Law exponent, n.

The apparent viscosity, or effective viscosity, defined as the ratio of the shear stress to the shear rate, varies with shear rate for non-Newtonian fluids. The apparent viscosity is the slope of a line from the origin to some particular shear rate. The slopes of the dashed lines in Fig. 14 represent apparent viscosities at various shear rates. The apparent viscosity decreases with increased shear rate. This phenomenon is called "shear thinning." As shear rates approach infinity, the apparent viscosity reached a limit called the

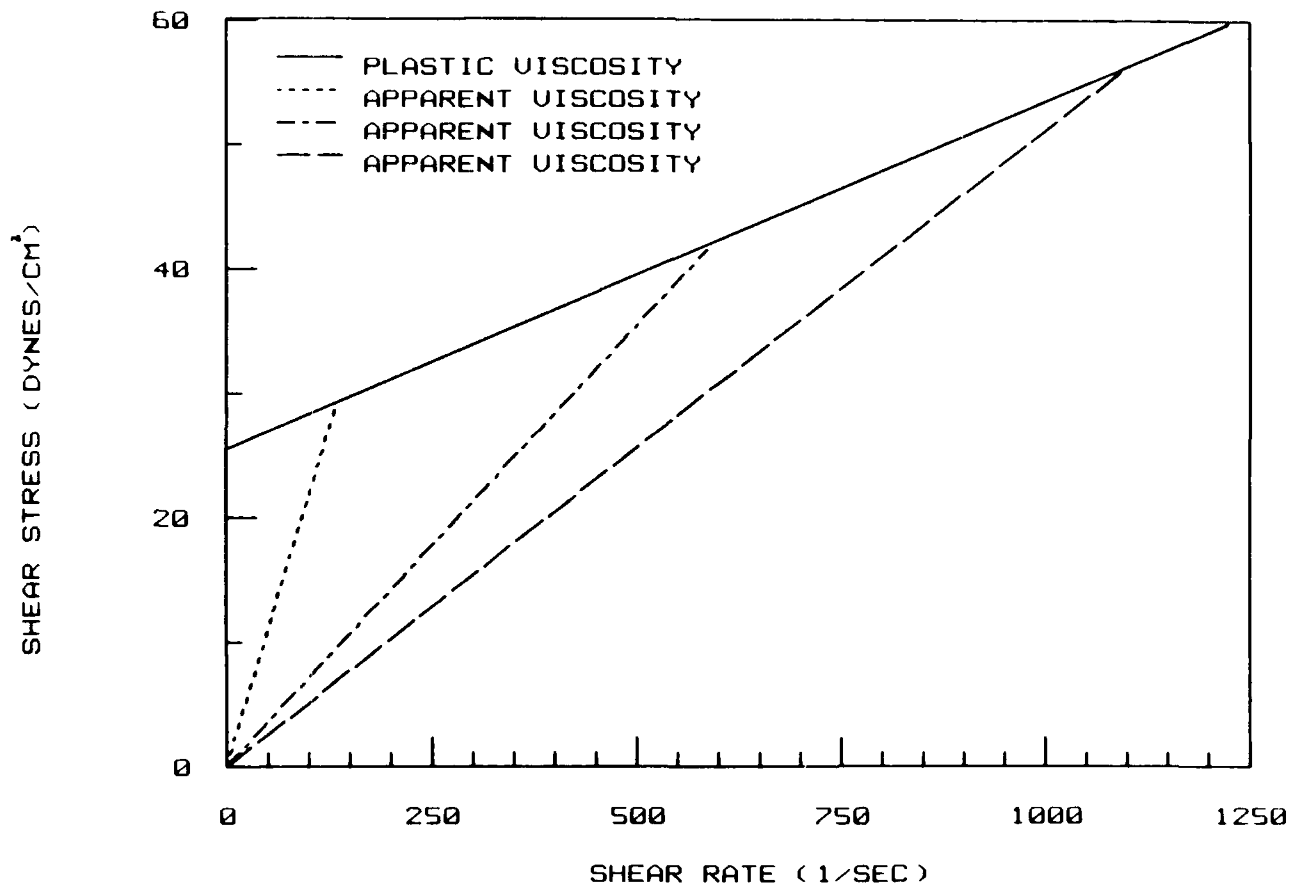


Fig. 14 - Flow curve for a Bingham plastic fluid.

"plastic viscosity"[37]. The plastic viscosity is the slope of the Bingham Plastic flow curve.

This model has been used extensively in the oil industry. The model is easy to use, and it represents many drilling fluids reasonably well. In fact, the commonly used Fann V-G meter was specifically designed to facilitate the use of the Bingham Plastic model in the field. However, the Bingham model usually does not represent drilling fluids at low shear rates. More sophisticated fluid models are gaining a wider acceptance in the oil field as engineers become more familiar with their use.

Ostwald-deWaele Pseudoplastic (Power Law) Model

The pseudoplastic flow curve is characterized by a non-linear relationship between shear rate and shear stress as shown in Fig. 15[37]. Velocity profiles for pseudoplastic materials tend to be flatter than those for Newtonian fluids, but normally a plug does not develop[39]. The relationship for the typical pseudoplastic fluid is given by

$$\tau = k\,\gamma^{n} \qquad (38)$$

Generally speaking, the consistency factor, k, describes the thickness of the fluid and is somewhat analogous to apparent viscosity. As k increases the mud becomes thicker. The flow behavior index, n, indicates the degree of non-Newtonian behavior. When n equals one, the Power Law equation becomes identical to the Newtonian

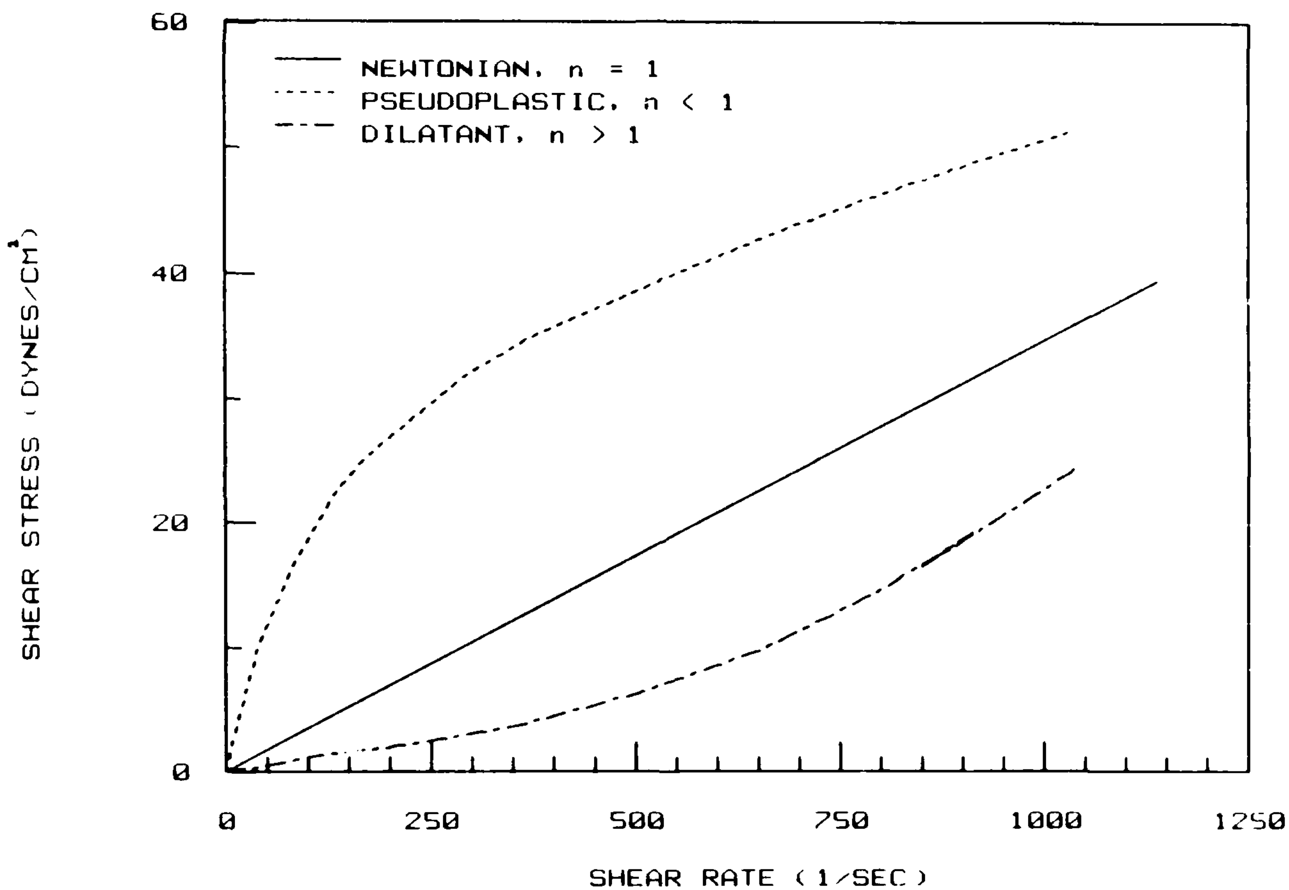


Fig. 15 - Flow curves for power law fluid.

as dilatant; the apparent viscosity increases as shear rate increases. If n is greater than zero, but less than unity, the fluid is classified as pseudoplastic. Pseudoplastic fluids exhibit "shear thinning," which means that the apparent viscosity decreases as the shear rate increases. For drilling purposes, shear thinning is a very desireable property, and the majority of drilling fluids are pseudoplastic.

The Power Law model is widely used in the oil industry and has replaced the Bingham model, to some extent. The Power Law model is frequently more convenient than the Bingham model. It is particularly suitable for graphical techniques since rotary viscometer readings versus rpm and flow-pressure loss versus flow rate can be plotted as straight lines on log-log paper. The Power Law model also more accurately demonstrates the behavior of a drilling fluid at low shear rates. However, the Power Law does not include a yield stress and therefore can give poor results at very low shear rates[37].

Fig. 16 compares the flow curve of a typical drilling fluid to the flow curves of Newtonian, Bingham Plastic, and Power Law fluids. The typical drilling fluid exhibits a yield stress and shear thinning. At high rates of shear, all models represent the typical drilling fluid reasonably well. Differences between the fluid models are most pronounced at low shear rates. The Bingham Plastic fluid includes a simple yield stress, but does not accurately describe the fluid behavior at low shear rates. The Power Law more accurately describes the behavior at low shear rates, but does not include a yield stress.

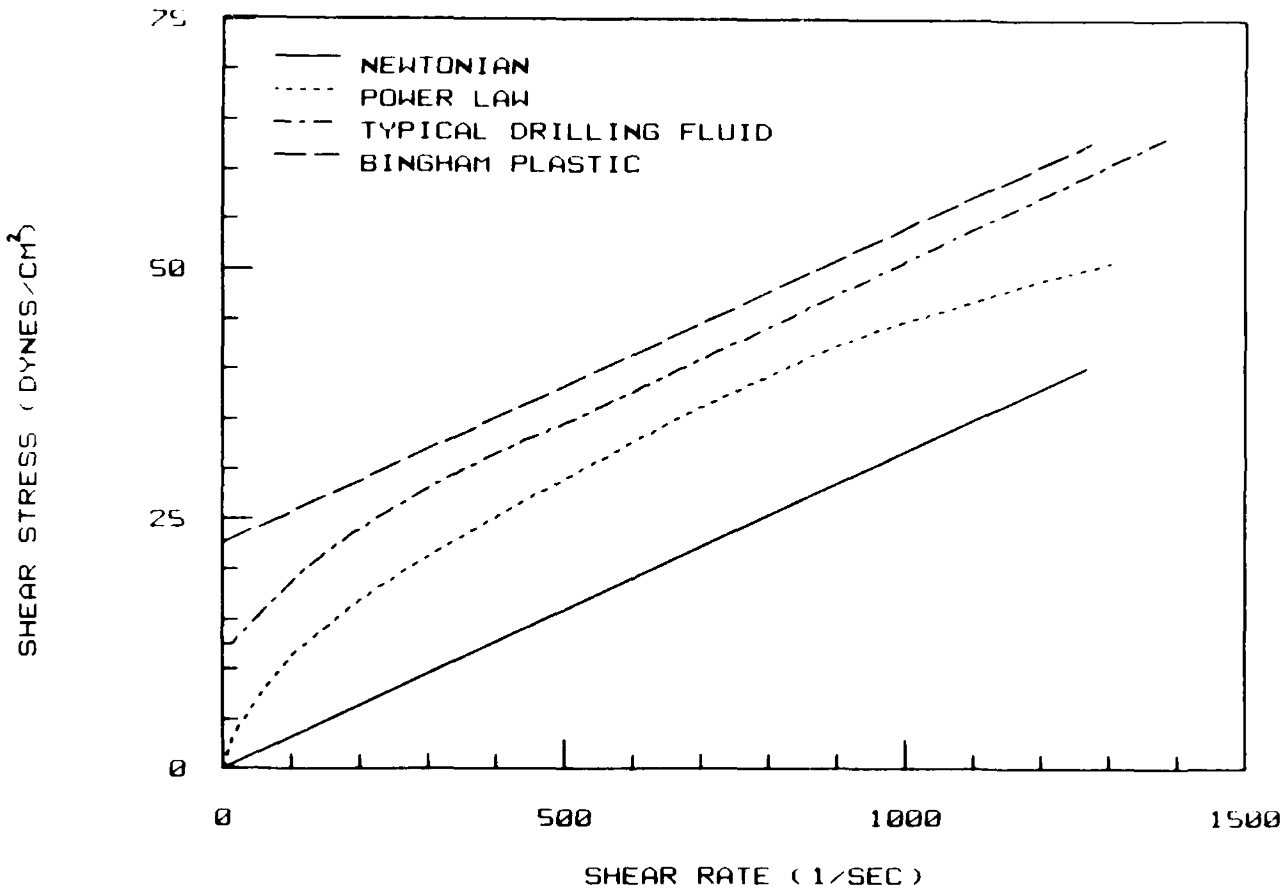


Fig. 16 - Typical drilling fluid versus Newtonian, Bingham plastic, and power law fluids.

The typical drilling fluid exhibits behavior in between the Bingham model and the Power Law model.

Recently attempts have been made to resolve the controversy by proposing models that combine the obvious shear thinning features of drilling fluids with a yield stress. These proposed models include the Casson, Robertson - Stiff, and Herschel - Bulkley models. However, for the purposes of this study, these models will not be discussed.

VERIFICATION OF THE MODEL

The heat transfer and temperature distribution prediction model has been compared with data presented by two different authors to ensure that this simulator in fact does present reasonable results. The data used for the comparison is from papers by Ramey[8] and Holmes and Swift[13]. Table 1 lists the information used to compare the data generated by this model with those of the two previously mentioned references. These data are also the default data which are built in to the program and from which all parameter variations begin. These data are actual data obtained from a 15,000 foot Gulf Coast well.

For the case of the Holmes and Swift[13] paper, the well was assumed to have no drill bit size change and no casing set. Fig. 17 illustrates the temperature profiles of the mud in the annulus and the mud in the drill pipe. It appears that the maximum mud temperature generally occurs in the annular fluid at some point above the bottom of the hole. This phenomenon was also presented by the Tragesser *et al.*[10] model and agrees with distributions obtained from measured mud temperatures during mud circulation[13]. For the purposes of providing a beginning point for Figs. 17 through 21, the assumed geothermal profile is included on all these figures. This is the solid curve on each graph. Also, for simplicity, only the annulus temperatures have been plotted in the figure. However, the drill pipe temperatures obtained for each run would follow the same trend as that shown in Fig. 17.

TABLE 1 -- PROPERTIES USED IN THE COMPUTER MODEL AND THEIR DEFAULT VALUES

Property	Units	Default Value
DRILLING FLUID:		
Thermal conductivity	Btu/(hr*ft *deg F)	1.0
Inlet temperature	deg F	75.0
Mud density	lb/gal	10.0
Flow rate	gal/min	210.0
Mud viscosity	lb/(ft*hr)	110.0
Specific heat	Btu/(lb*deg F)	0.4
DRILL PIPE:		
Heat transfer coefficient	Btu/(hr*sq ft *deg F)	30.0
Inner diameter	inches	5.965
Outer diameter	inches	6.625
Incremental length (delz)	feet	500.0
WELLBORE/FORMATION:		
Depth	feet	15,000.0
Temperature gradient	deg F/ft	0.0127
Surface air temp	deg F	70.0
Diameter	inches	8.375
Heat transfer coefficient	Btu/(hr*sq ft *deg F)	1.0
CASING:		
Thermal conductivity	Btu/(hr*ft *deg F)	25.0
Inner diameter	inches	10.0
Outer diameter	inches	10.75
Weight	lb/ft	51.0
Grade		N-80

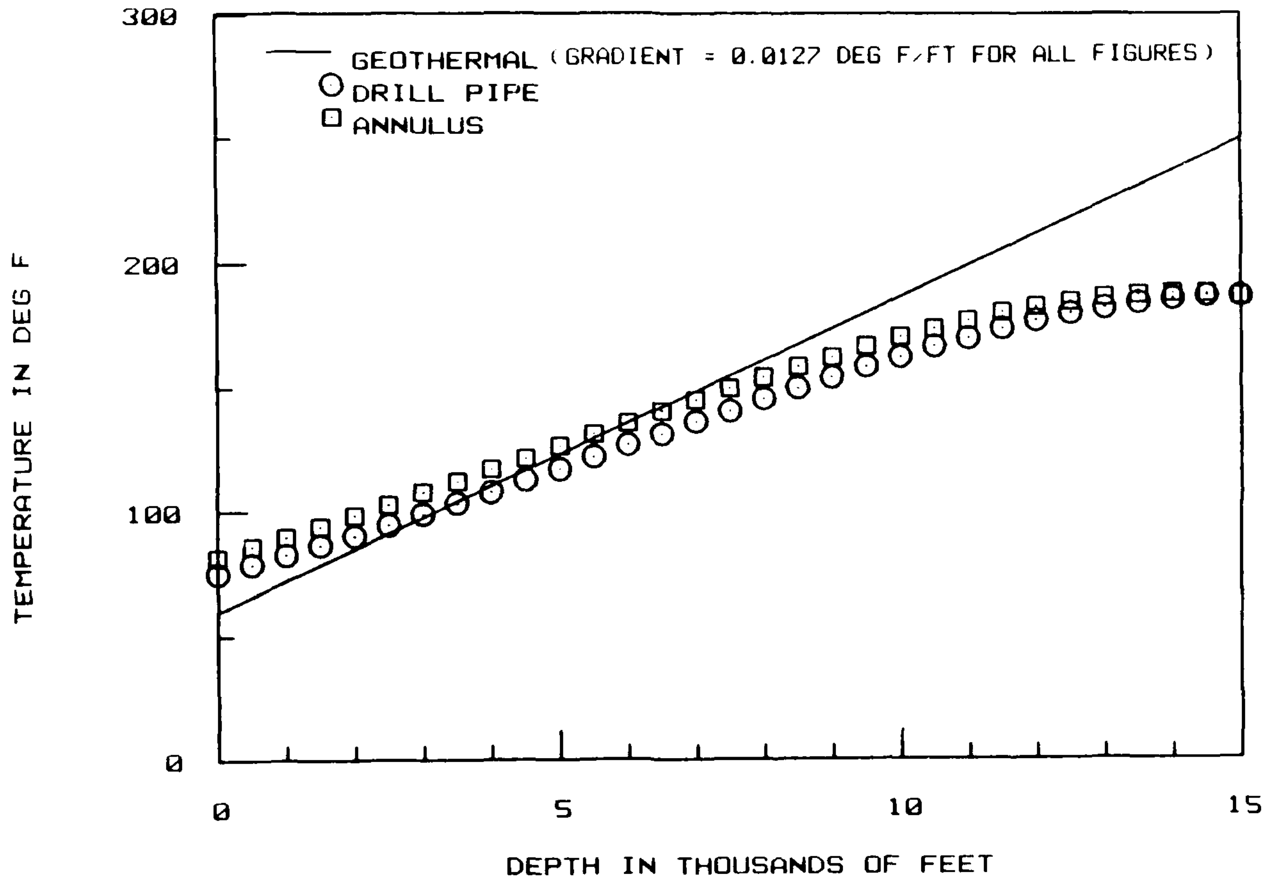


Fig. 17 - Temperature for the fluid in the annulus and drill pipe during circulation.

PARAMETRIC SENSITIVITY ANALYSIS

The primary purpose in performing such an analysis is to establish to what extent variations in a particular parameter will effect the temperature distribution in the wellbore. This is of particular interest where the parameter in question cannot be directly evaluated. In such a case, the degree to which variations in this parameter would affect the temperature indicate how important is an accurate estimate for the parameter. It also provides a qualitative estimate of the error intrinsic in the simulator caused by using assumed values.

Some parameters which have a distinct influence on the temperature profile on the fluid flowing on a circulating well can be directly and accurately measured. These include circulating time, depth, wellbore geometry, and drilling fluid characteristics. Hence, such a detailed analysis is of somewhat less importance with regard to these parameters, but nonetheless appropriate in view of the fact that it can be used to evaluate the validity of assuming some of them to remain constant.

Any computer simulator of such an imprecise and complicated an operation as drilling a well must be a simplification. The fewer the simplifications and assumptions, the more accurate the model will be. Unfortunately, there is no physical means for determining the dynamic temperature distribution in a well, and thus there is no independent method of accessing the accuracy of the model. For this reason, any variation in a parameter that caused a maximum deviation of less than

5°F was considered insignificant. It should be noted that interaction between parameters was disregarded and that if several of the parameters were varied simultaneously, it is likely that the total effect could be significant, whereas individually the variation had an insignificant effect.

Fig. 18 demonstrates the effect of varying wellbore and drill pipe diameters in the wellbore on the temperature of the mud in the annulus during circulation. Table 2 and 3 provide the critical information that was used in the generation of the data for the plot in Fig. 18. Fig. 18 shows that as the diameter of the wellbore is increased, the bottomhole temperature also increases. However, as you decrease the diameter of drill pipe, the bottomhole temperature tends to decrease. It does appear that this effect is reversed somewhat in the upper portion of the wellbore. In this simulation, the temperatures in the annulus are approximately equal at a depth of about 4,000 feet. By increasing the diameter of the wellbore to 12 inches, the bottomhole temperature increased about 8°F. The bottomhole temperature was found to decrease by about 16°F, after decreasing the drill pipe diameter to 4 inches.

Fig. 19 illustrates the effect of varying mud circulation rates. Table 4 lists the critical data that was used in the generation of the data for the plot in Fig. 19. Fig. 19 reveals that as the mud circulation rate increases, the temperature distribution in the annulus decreases. On the other hand, as you decrease the mud circulation rate, the temperature in the wellbore increases. A 33.3

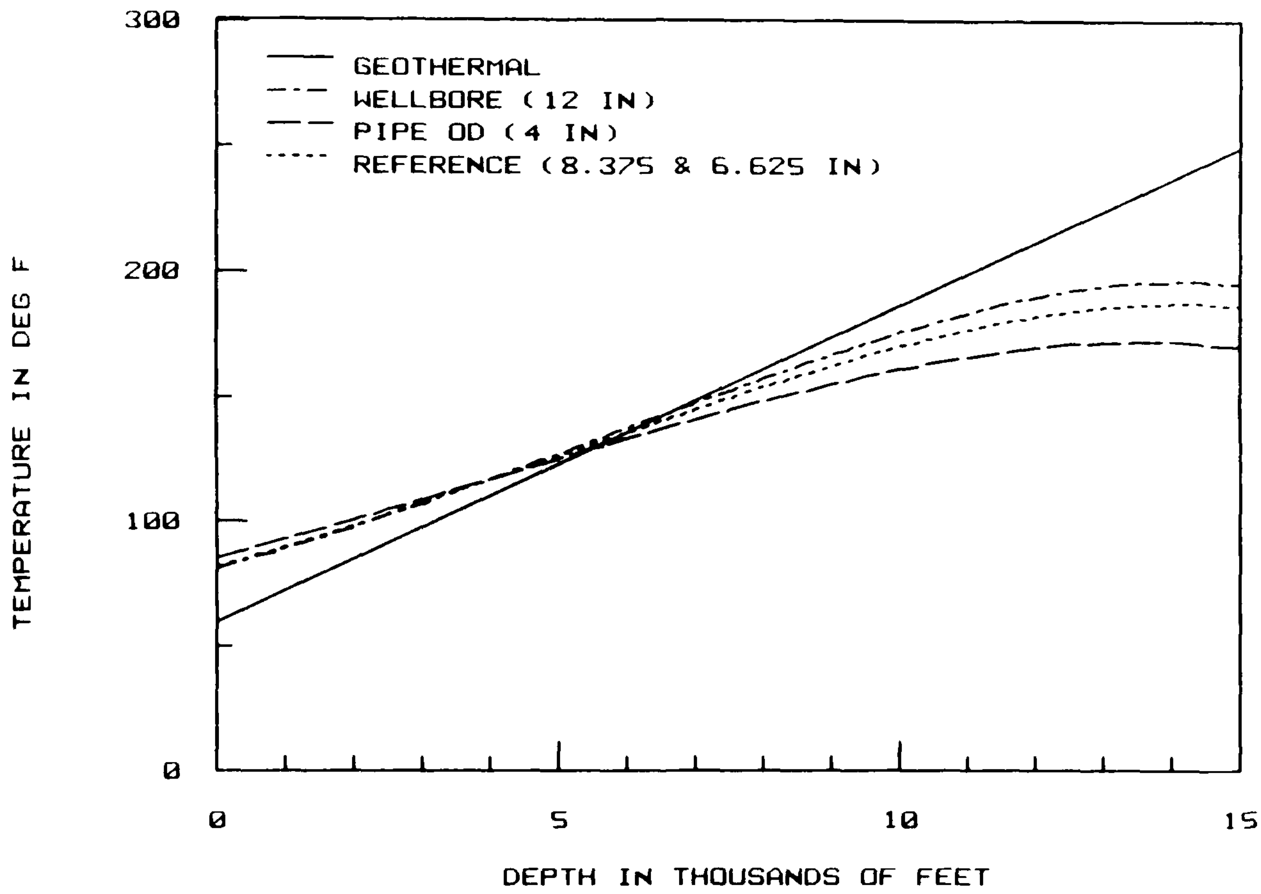


Fig. 18 - Effect of varying diameters on the temperature of the annulus during circulation.

TABLE 2 -- WELL DATA SUMMARY FOR VARYING WELLBORE DIAMETER

Wellbore diameter	=	varies (inches)[1]
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[1] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

TABLE 3 -- WELL DATA SUMMARY FOR VARYING DRILL PIPE OUTER DIAMETER

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	varies (inches)[2]
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[2] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

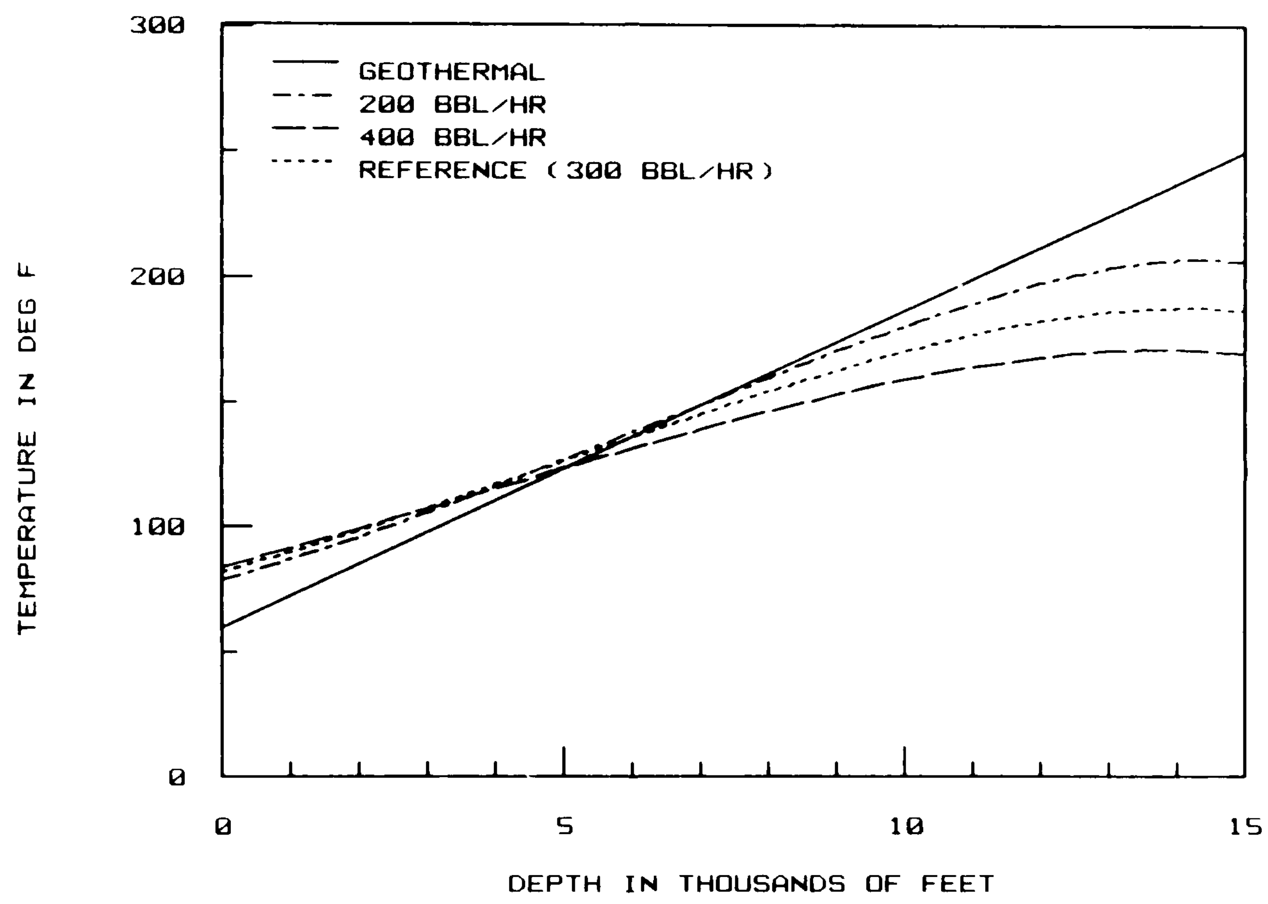


Fig. 19 - Effect of varying mud flow rate on the temperature of the annulus during circulation.

TABLE 4 -- WELL DATA SUMMARY FOR VARYING MUD FLOW RATE

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	varies (bbl/hr)[3]
Heat transfer coefficient (pipe)	=	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[3] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

percent decrease in the flow rate resulted in a 20°F increase in the bottomhole temperature. Increasing the flow rate by 33.3 percent resulted in a 17°F decrease in the bottomhole temperature. Although the flow rate has a significant effect on the annular temperature distribution, it can be reliably measured. As was the case in Fig. 18, it appears that this effect is reversed slightly above the 4,000 foot level in the wellbore.

Fig. 20 shows the effect of varying the heat transfer coefficient of the drill pipe on the temperature of the annulus during circulation. Table 5 lists the data used for the generation of this plot. As demonstrated in Fig. 20, as the heat transfer coefficient of the pipe is increased, the temperature in the annulus begins to increase also. As the heat transfer coefficient on the pipe is decreased, the temperature in the annulus also decreases. An increase in the heat transfer coefficient of 66.7 percent resulted in an increase of 14°F in the wellbore, and a decrease of 66.7 percent resulted in a temperature reduction of 38°F. This is obviously a critical parameter to be considered in any computer model. As in previous examples, this effect also appears to be reversed in the upper portion of the well.

Fig. 21 illustrates the effect of varying the heat transfer coefficient of the annulus on the temperature of the mud in the annulus during circulation. Table 6 lists the data that was used to generate the data for this plot. As shown in Fig. 21, as the heat transfer coefficient in the annulus is increased, the temperature in

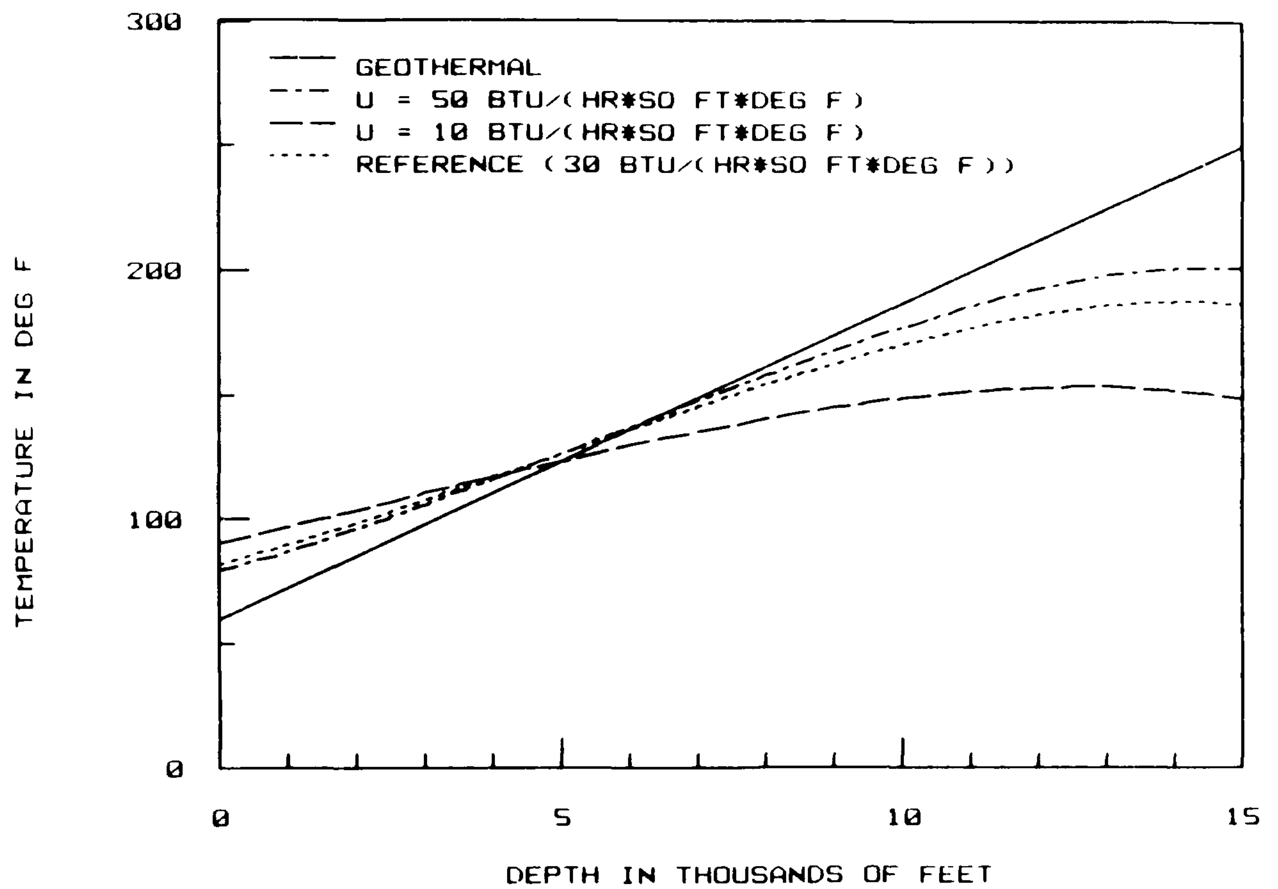


Fig. 20 - Effect of varying heat transfer coefficient (pipe) on the temperature of the annulus during circulation.

TABLE 5 -- WELL DATA SUMMARY FOR VARYING HEAT TRANSFER COEFFICIENT (PIPE)

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	varies (Btu/(hr*ft*°F))[4]
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[4] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

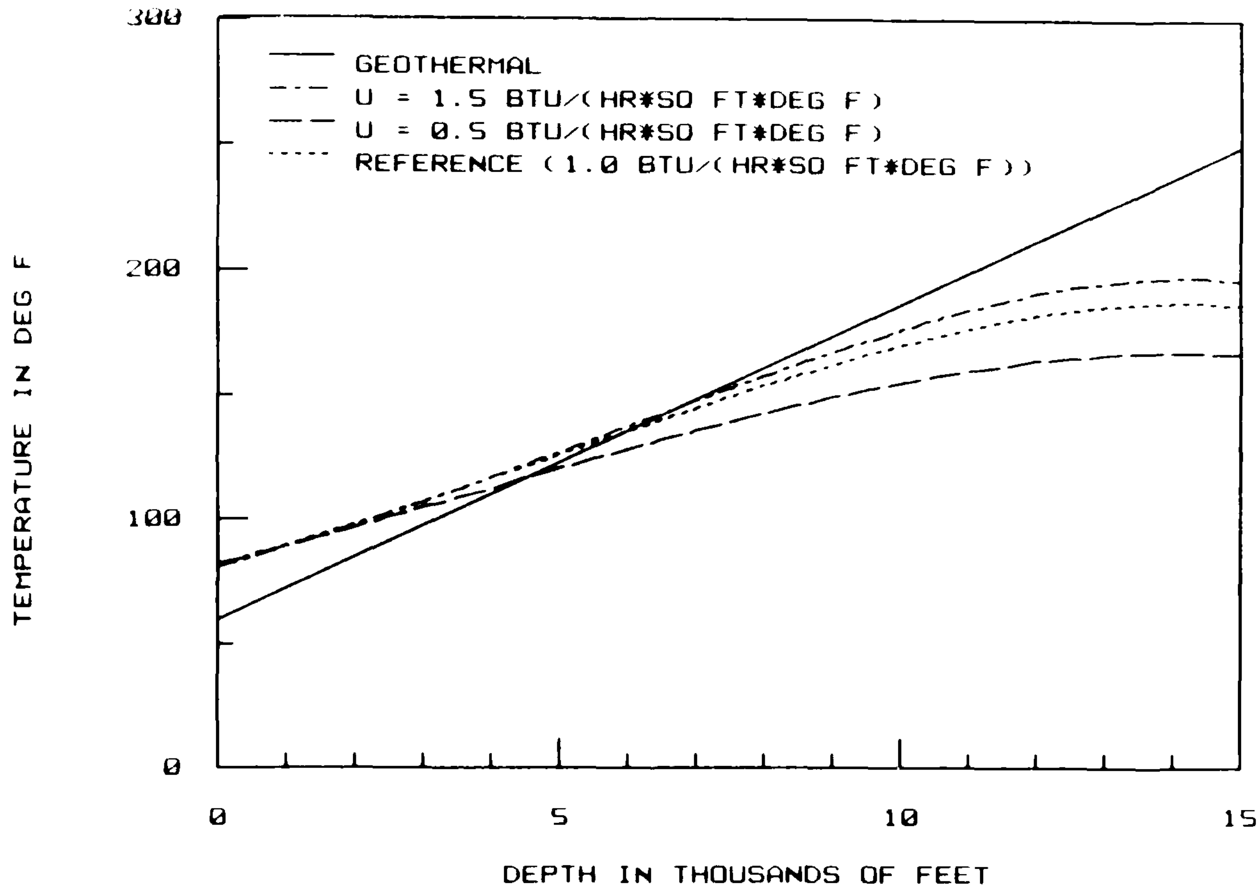


Fig. 21 - Effect of varying heat transfer coefficient (annulus) on the temperature of the annulus during circulation.

TABLE 6 -- WELL DATA SUMMARY FOR VARYING HEAT TRANSFER COEFFICIENT (ANNULUS)

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	varies (Btu/(hr*ft*°F))[5]
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[5] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

the annulus is found to also increase. As the heat transfer coefficient of the annulus decreases, so does the temperature of the mud in the circulating wellbore. Increasing the heat transfer coefficient by 100 percent resulted in a temperature increase of 10°F in the annulus. A decrease of 100 percent resulted in a temperature decrease of approximately 20°F. This parameter is difficult to obtain an accurate estimate, and one finds much written in the literature regarding its determination.

Fig. 22 shows the effects of varying the specific heat of the mud on the temperature of the annulus. Increasing or decreasing this parameter by 50 percent, covers the range of values quoted in the literature, resulted in large variations in the temperature of the wellbore annulus. An increase of 50 percent in this parameter resulted in a bottomhole temperature decrease of 25°F. A similar decrease in the specific heat resulted in a bottomhole temperature increase of 30°F. Since a small change in the value of this parameter results in a large alteration in the annular temperature profile, and as the variation of this parameter within the system cannot accurately be assessed, it is very significant. Table 7 lists a summary of the combination of variables used for this comparison.

Increasing the fluid density from 10 lb/gal to 13.4 lb/gal decreased the bottomhole temperature by 17°F, while increasing it to 16 lb/gal decreased the bottomhole temperature by 29°F. The resulting annular temperature profiles are shown in Fig. 23. Although the density of the fluid is known with reasonable accuracy upon entering

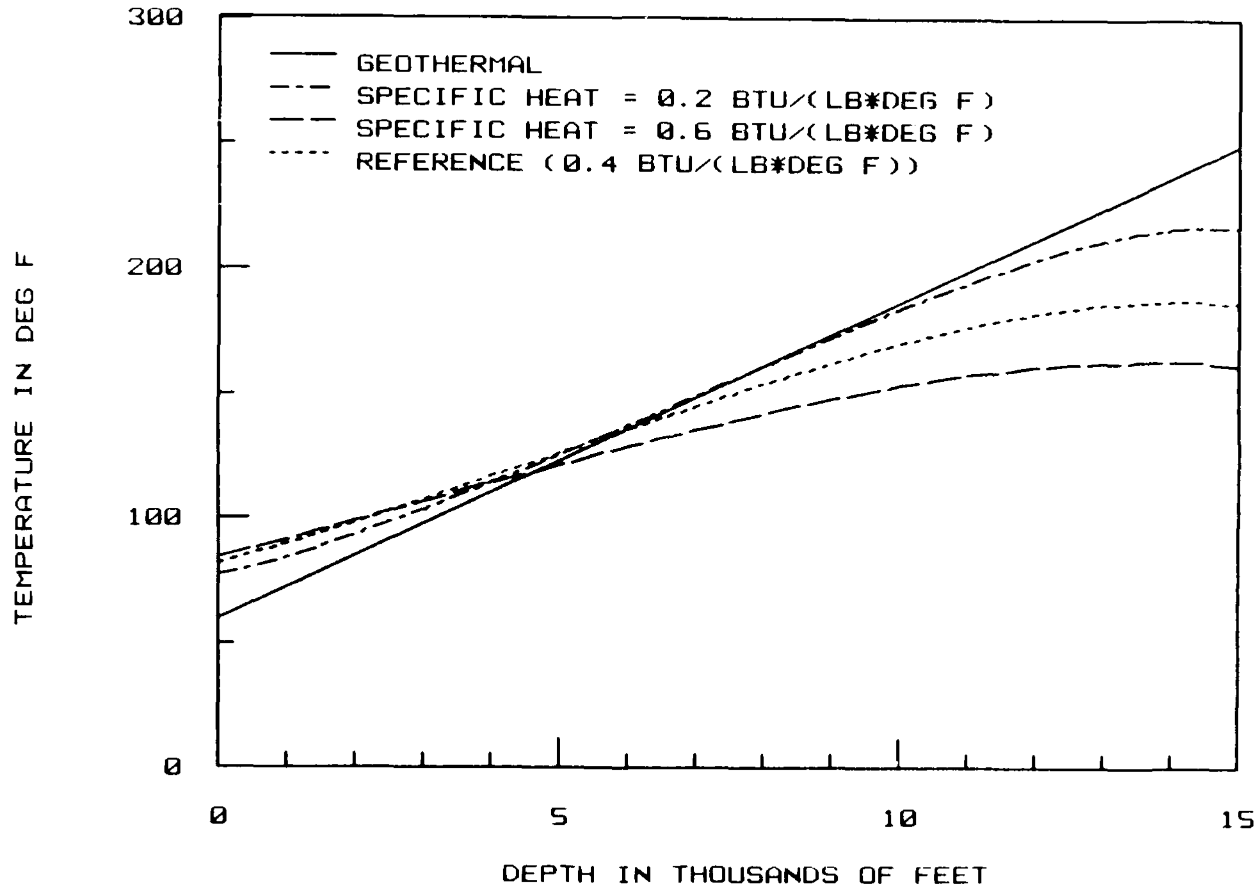


Fig. 22 - Effect of varying specific heat of mud on the temperature of the annulus during circulation.

TABLE 7 -- WELL DATA SUMMARY FOR VARYING SPECIFIC HEAT OF THE DRILLING MUD

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	300 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	varies (Btu/(lb*°F))[6]
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[6] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

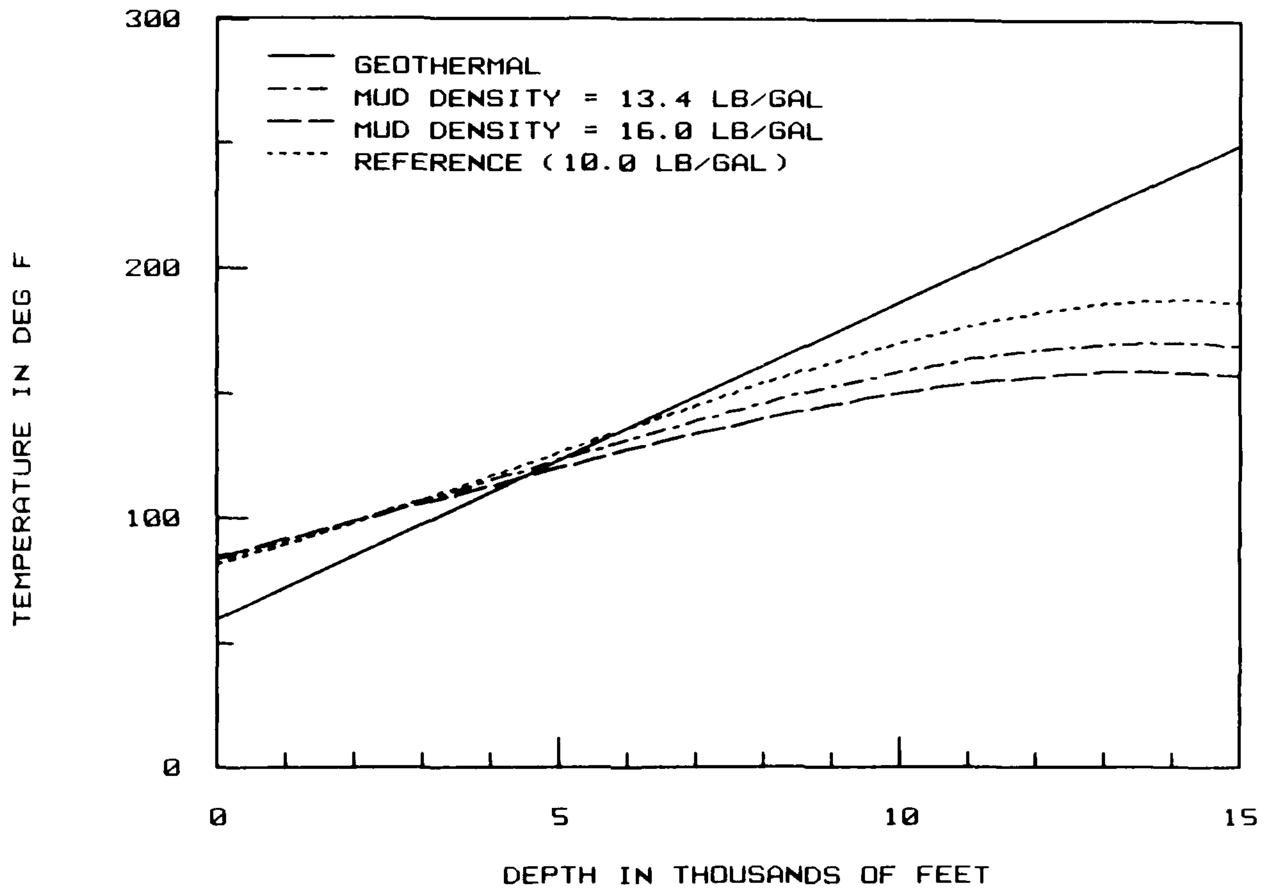


Fig. 23 - Effect of varying mud density on the temperature of the annulus during circulation.

the system, its variations within the system are not. In particular, the fluid density will increase due to the addition of drill cuttings during drilling operations. Table 8 summarizes the variables used in this particular analysis.

Alterations in the geothermal gradient have a distinct effect on the temperature profile in the annulus as illustrated in Fig. 24. Inasmuch as this parameter will remain constant for a particular well, it cannot be determined with any degree of precision. Fig. 24 indicates that a poor assumption of the value of the geothermal gradient will cause errors in the annulus temperature distribution. The range of values in Fig. 24 is representative of the values quoted in the literature. Table 9 provides a list of the parameters used in this portion of the study.

The inlet fluid temperature can be accurately measured. However, Fig. 25 illustrates the need to insure that this parameter should be continuously monitored during drilling operations to be certain that the annulus temperature profiles as predicted by the model are accurate. Variables used in this analysis are found in Table 10.

Fig. 26 illustrates that the temperature profile in the annulus is relatively insensitive to this parameter with a maximum variation in the annulus temperature profile of about 20°F at the largest hydraulic radius evaluated. Table 11 list the values of the parameters used in this evaluation.

These data and graphs agree with the results of Holmes and Swift[13] very closely. When comparing Figs. 17 through 21 with the

TABLE 8 -- WELL DATA SUMMARY FOR VARYING MUD DENSITY

Wellbore diameter	-	8.375 (inches)
Drill pipe O.D.	-	6.625 (inches)
Mud flow rate	-	300 (bbl/hr)
Heat transfer coefficient (pipe)	-	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	-	1 (Btu/(hr*ft*°F))
Specific heat	-	0.4 (Btu/(lb*°F))
Mud density	-	varies (lb/gal)[7]
Geothermal grad.	-	0.0127 (°F/ft)
Inlet temperature	-	75 (°F)
Hydraulic radius	-	0.4375 (inches)

[7] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

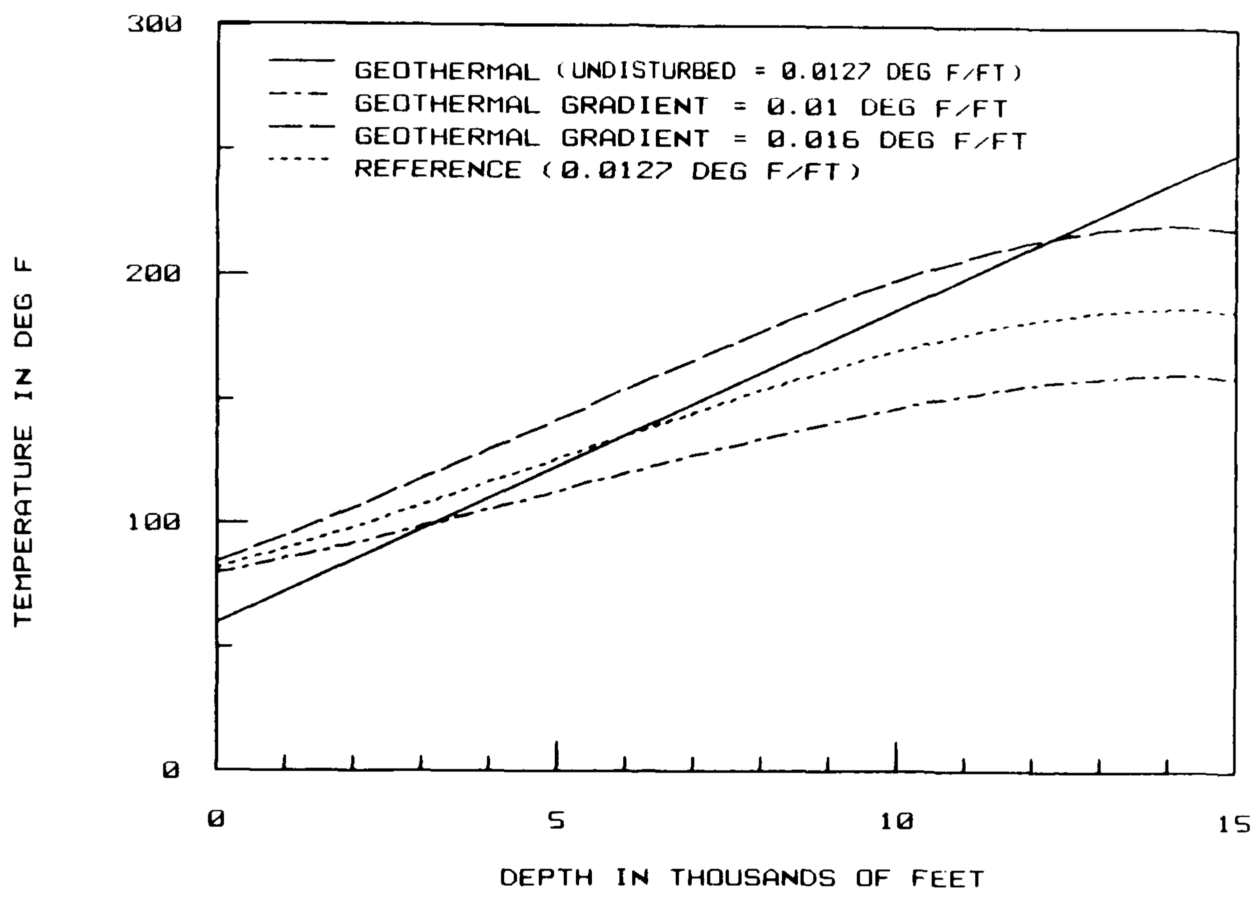


Fig. 24 - Effect of varying geothermal gradient on the temperature of the annulus during circulation.

TABLE 9 -- WELL DATA SUMMARY FOR VARYING GEOTHERMAL GRADIENT

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	varies (°F/ft)[8]
Inlet temperature	=	75 (°F)
Hydraulic radius	=	0.4375 (inches)

[8] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

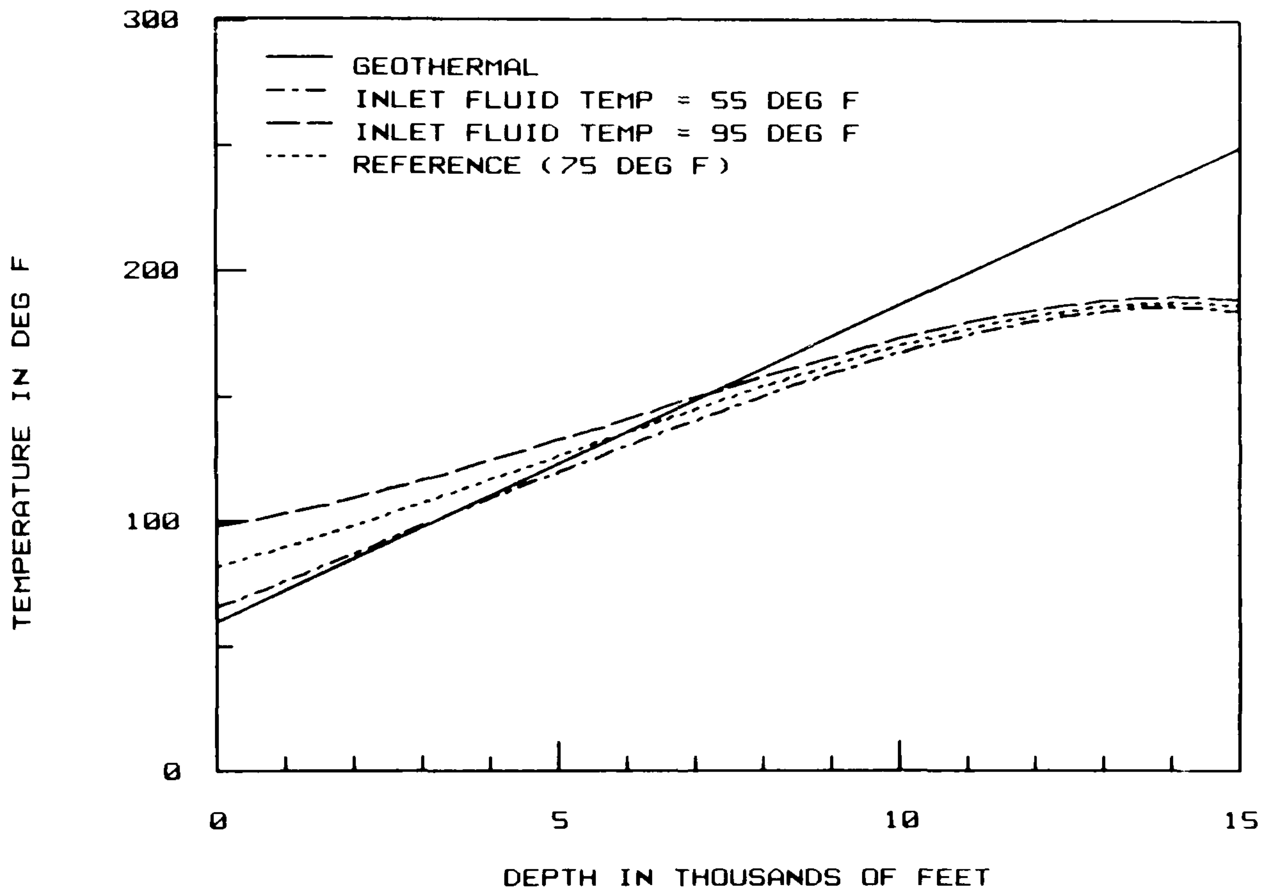


Fig. 25 - Effect of varying inlet fluid temperature on the temperature of the annulus during circulation.

TABLE 10 -- WELL DATA SUMMARY FOR VARYING INLET FLUID TEMPERATURE

Wellbore diameter	=	8.375 (inches)
Drill pipe O.D.	=	6.625 (inches)
Mud flow rate	=	300 (bbl/hr)
Heat transfer coefficient (pipe)	=	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	=	1 (Btu/(hr*ft*°F))
Specific heat	=	0.4 (Btu/(lb*°F))
Mud density	=	10.0 (lb/gal)
Geothermal grad.	=	0.0127 (°F/ft)
Inlet temperature	=	varies (°F)[9]
Hydraulic radius	=	0.4375 (inches)

[9] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

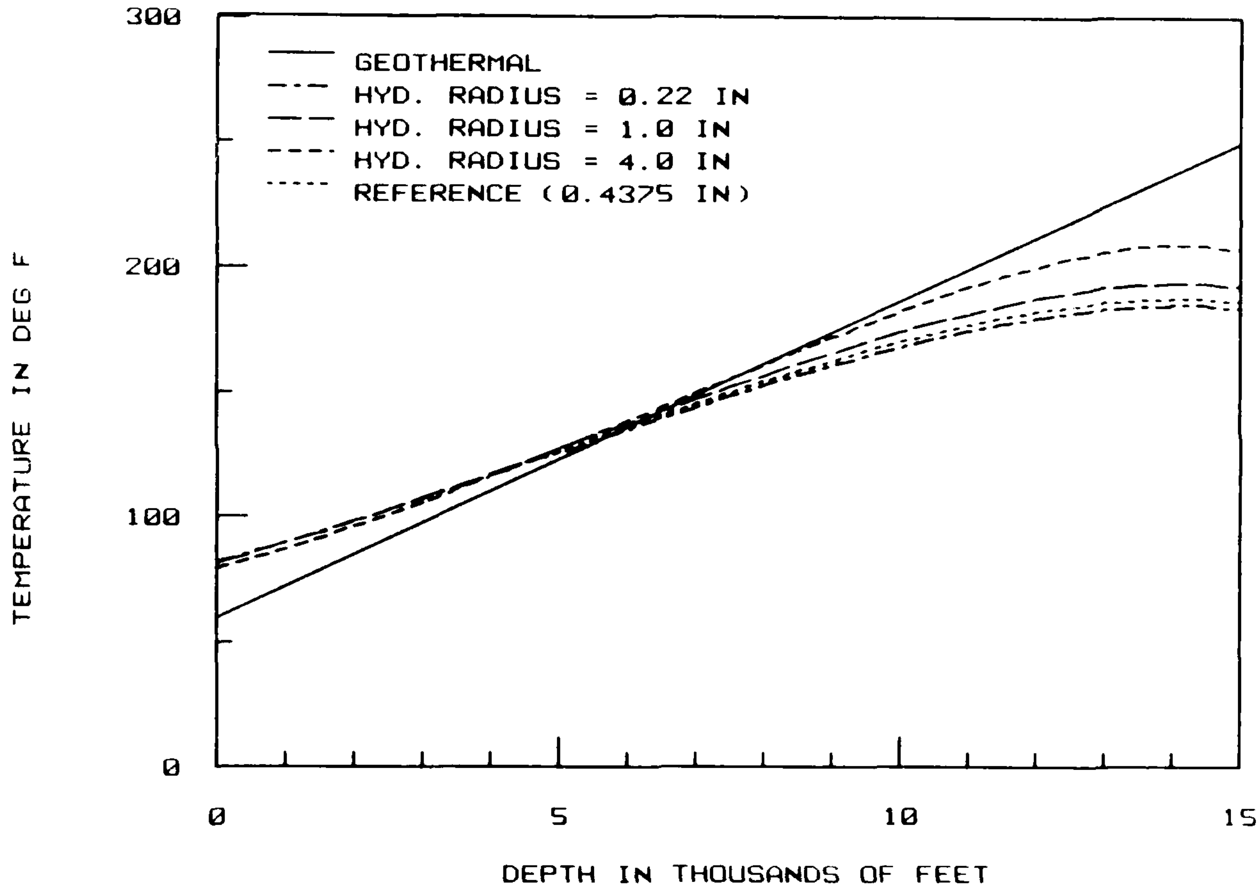


Fig. 26 - Effect of varying hydraulic radius on the temperature of the annulus during circulation.

TABLE 11 -- WELL DATA SUMMARY FOR VARYING HYDRAULIC RADIUS

Wellbore diameter	-	8.375 (inches)
Drill pipe O.D.	-	6.625 (inches)
Mud flow rate	-	300 (bbl/hr)
Heat transfer coefficient (pipe)	-	30 (Btu/(hr*ft*°F))
Heat transfer coefficient (annulus)	-	1 (Btu/(hr*ft*°F))
Specific heat	-	0.4 (Btu/(lb*°F))
Mud density	-	10.0 (lb/gal)
Geothermal grad.	-	0.0127 (°F/ft)
Inlet temperature	-	75 (°F)
Hydraulic radius	-	varies (inches)[10]

---

[10] Refer to the appropriate figure to obtain information regarding the range of the parameter being varied.

figures of Holmes and Swift (Figs. 2 through 6)[13], very similar results can be obtained. Therefore, Figs. 22 through 26 are most likely to be representative of temperature effects on the annulus. Thus it has been shown that a steady-state analytical model can be developed to determine circulating mud temperature distributions for the annulus and drill string fluids. Figs. 27 through 30 provide a comparison of the data provided by the simulator described in this thesis, and the data provided by holmes and Swift[13]. As can be seen, excellent agreement exists. Therefore, this model provides a rapid method for computing mud temperature profiles and bottomhole mud temperatures so that appropriate mud an cement properties can be selected.

As for verification of the Ramey[8] model, it was found that the computer program generated very good agreement with Ramey's results. However, direct comparison with any data generated by Ramey could not be accomplished. Ramey[8] presented a method for the solution of the wellbore heat transfer problem which was a combination of hand calculations and application of his time function graph. He provides one calculation of temperature in a wellbore at a certain depth. When this point was compared with the data generated by the computer model, good agreement was obtained. However, it should be noted that Ramey's calculations involved round off error which was not present in the computer model. Fig. 31 is a graph of the computer-generated Ramey data. It also provides an example of the type of plotting function

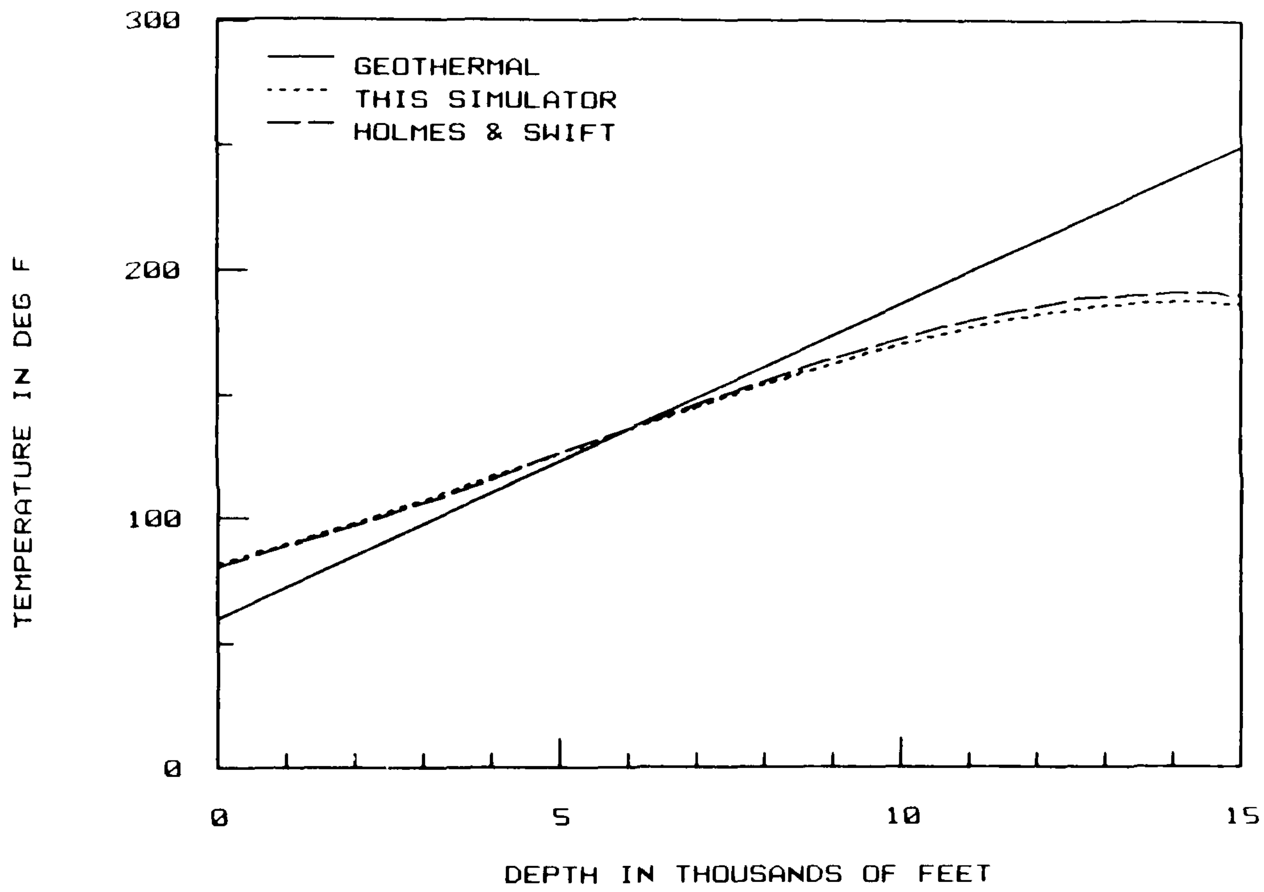


Fig. 27 - A comparison of the results of this simulator and those of Holmes and Swift using default data as presented in Table 1.

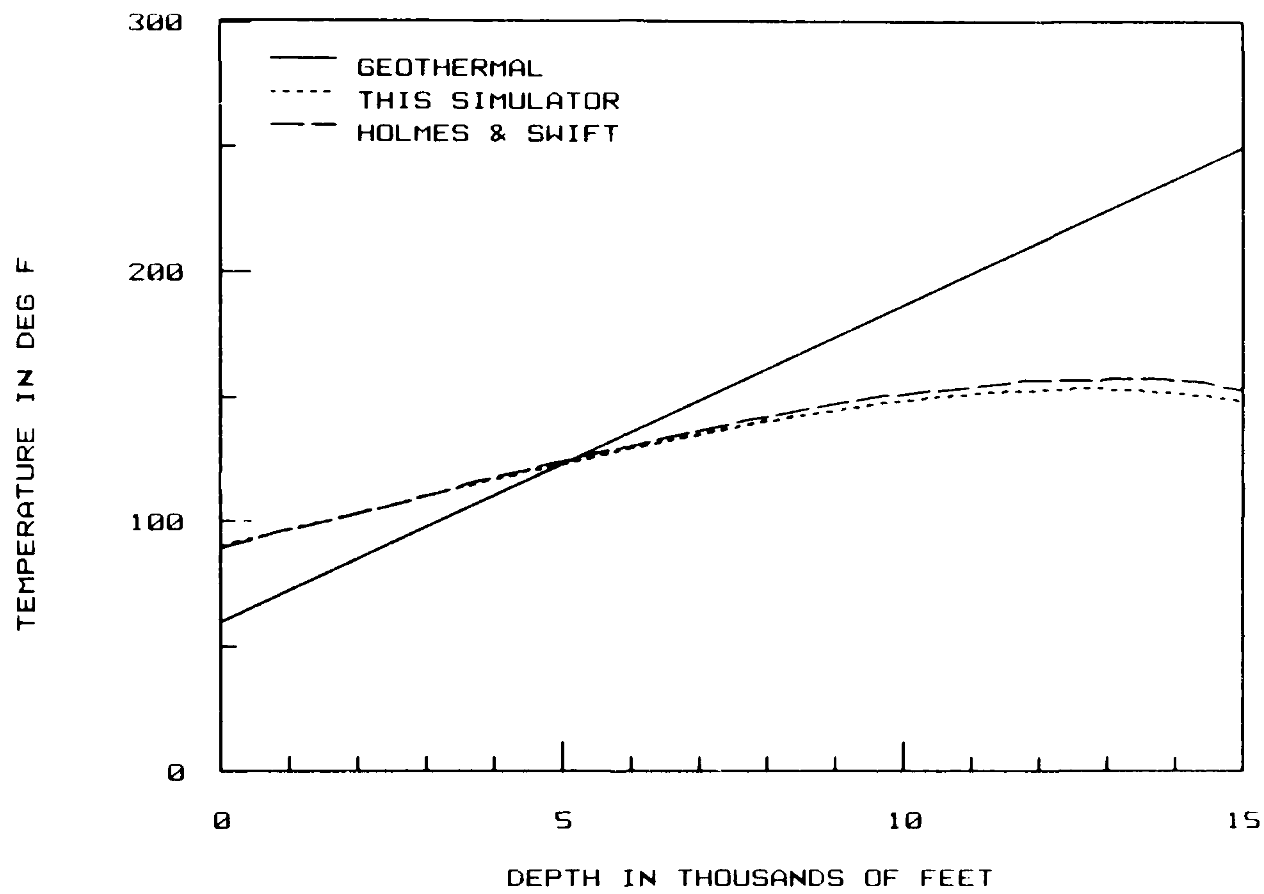
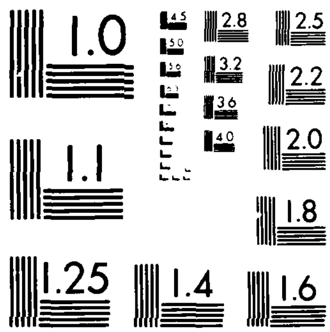


Fig. 28 - A comparison of the results of this simulator and those of Holmes and Swift using the same heat transfer coefficient (pipe). U = 10 Btu/(hr*sq ft*deg F).

AD-A189 306 A PC SIMULATION OF HEAT TRANSFER AND TEMPERATURE DISTRIBUTION IN A CIRCULATING WELLBORE(U) ARMY MILITARY PERSONNEL CENTER ALEXANDRIA VA R D PIERCE 19 NOV 87 2/2

UNCLASSIFIED F/G 8/7 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

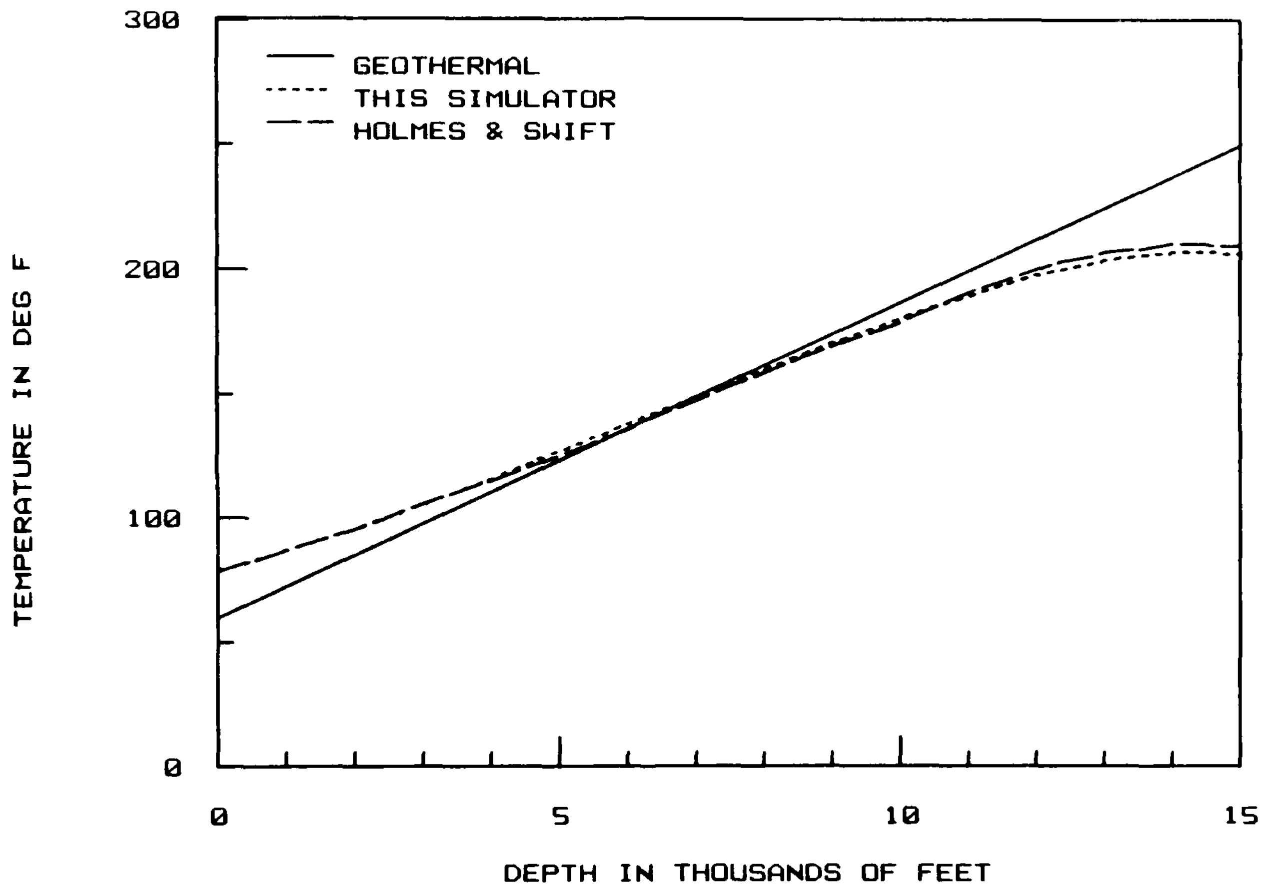


Fig. 29 - A comparison of the results of this simulator and those of Holmes and Swift using the same mud flow rate, 200 BBL/HR.

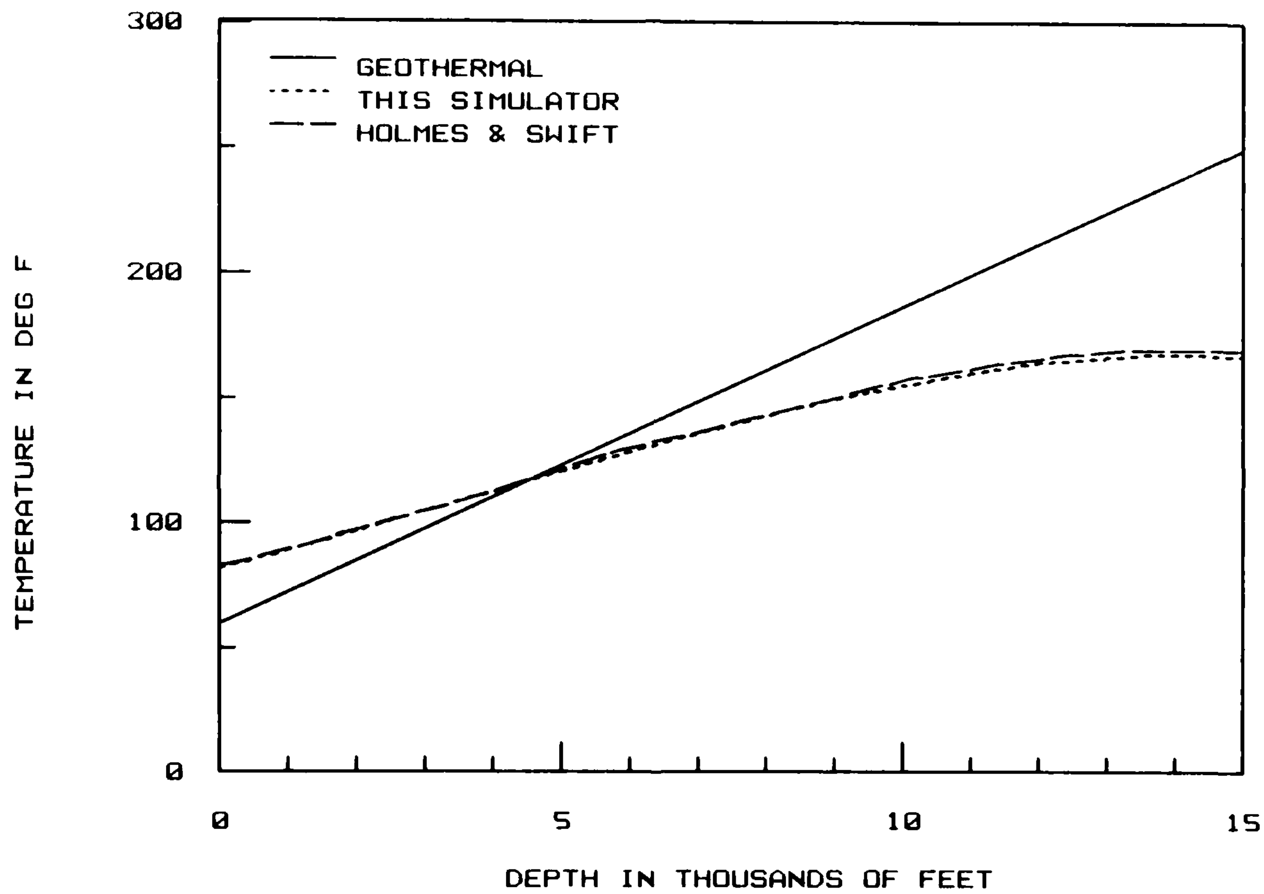


Fig. 30 - A comparison of the results of this simulator and those of Holmes and Swift using the same heat transfer coefficient (annulus), U = 0.5 Btu/(hr*sq ft*deg F).

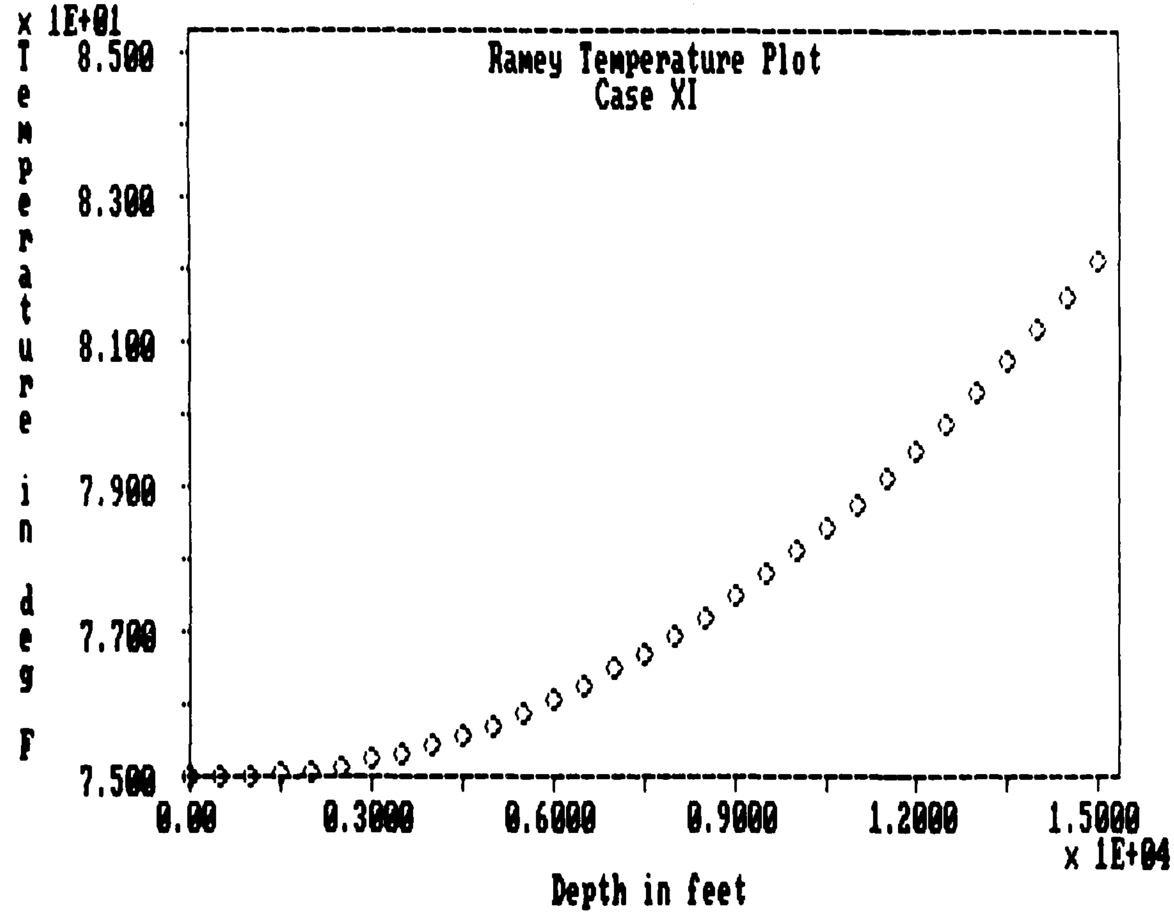


Fig. 31 - A plot of the Temperature profile in the wellbore using the equations of Ramey.

which is available in the computer model. This plot was produced by using the default parameters as found in Table 1.

It is also possible to calculate how the mud temperature profile is affected by the change in wellbore sizes due to drill bit changes during various phases of a drilling schedule. Using a 14,000 foot well as an example, it will be assumed that there was one change in drill bit size at 11,500 feet and changes in mud circulation rate at 10,000 feet and at 12,500 feet. To observe these effects, the mud temperature profiles would be calculated for the mud in the annulus and in the drill pipe for each segment of drilling. Fig. 32 illustrates a part of each mud circulation profile for each additional segment drilled. The end of each segment represents the bottomhole temperature at that point in the drilling schedule. By constructing a line through the bottomhole temperature calculated for each segment, we can observe any abnormalities originated by each change in the drilling of the well.

The model also works well in the calculation of pressure losses in the system for each of the three mud rheologies discussed: Newtonian; Bingham plastic, and; power law. The numbers provided by the computer model were verified by hand calculations and by comparison with example provided by Bourgoyne *et al.*[35]. Representative computer output for the three mud rheologies is provided in Figs. 33 through 35.

There is no evidence from this research to indicate that any of the major assumption enumerated in the Introduction are invalid.

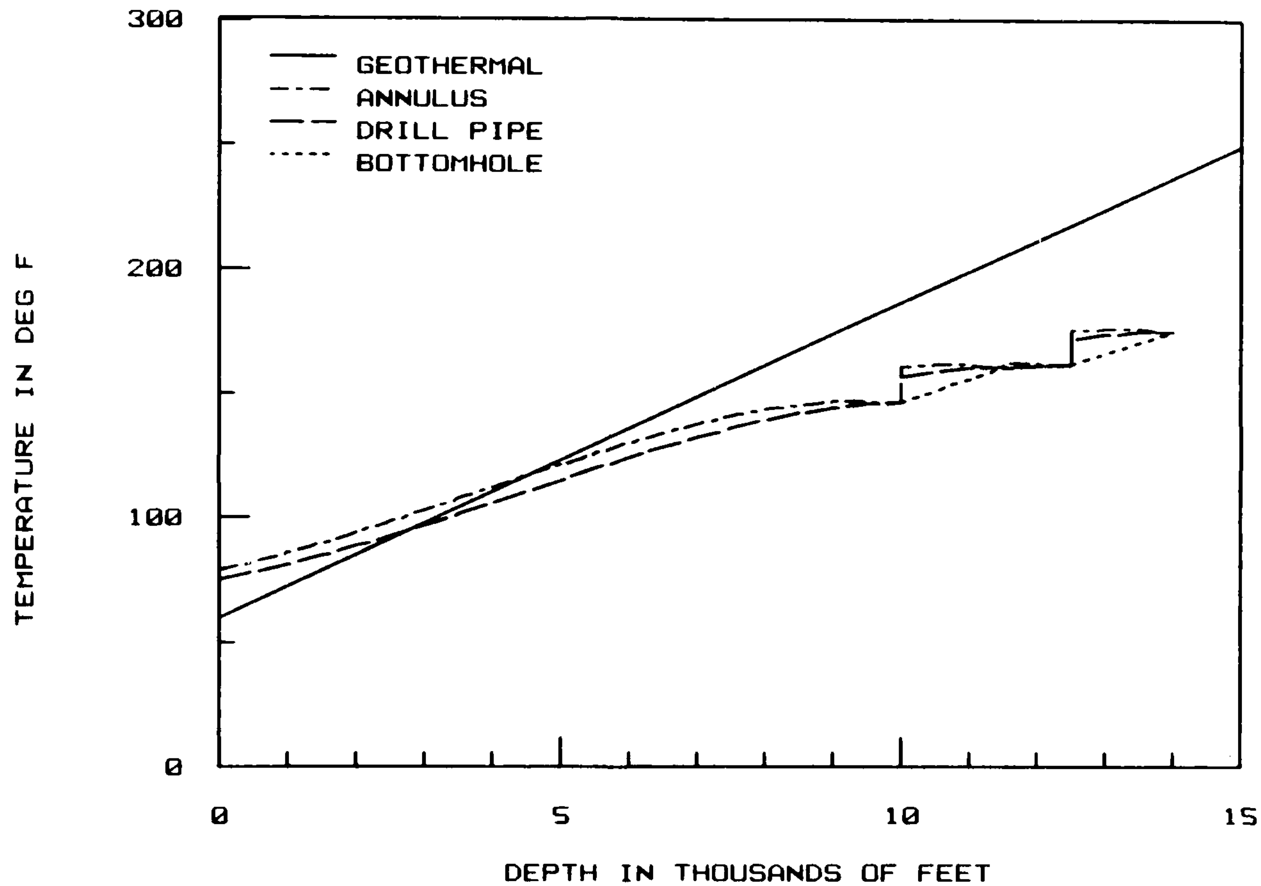


Fig. 32 - Temperature during drilling interval versus depth for construction of bottomhole temperature curves.

```
                         Fluid Flow Conditions
                  11-03-1987 xxx 11:35:20

Fluid model chosen is Newtonian

        Average velocity in drill pipe =     2.41  ft/sec
        Average velocity in the annulus =    1.33  ft/sec
        Reynold's Number in drill pipe =      2,935 TURBULENT
        Reynold's Number in annulus =        1,061 LAMINAR
        Darcy friction factor = 0.03727
        Prandtl Number = 18.190
        Nusselt Number =      35.95
        Pressure loss in drill pipe =      60.9  psi
        Pressure loss in annulus =     27.8  psi
        Pressure loss in bit =    268.6  psi
        Total Pressure loss in system =    357.2 psi

Hit any key to return to Fluid Rheology menu.
```

Fig. 33 - An example of Newtonian fluid pressure loss calculations.

```
xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx
xxxxxxxxxxxxxxxxxxxxxx                                          xxxxxxxxxxxxxxxxxxx
xxxxxxxxxxxxxxxxxxxxxx          Fluid Flow Conditions           xxxxxxxxxxxxxxxxxxx
xxxxxxxxxxxxxxxxxxxxxx                                          xxxxxxxxxxxxxxxxxxx
xxxxxxxxxxxxxxxxxxxxxxxxxxx 11-03-1987 xxx 11:35:47 xxxxxxxxxxxxxxxxxxxxxxxxxxx

Fluid model chosen is Bingham Plastic

         Average velocity in drill pipe =     2.41  ft/sec
         Average velocity in the annulus =     1.33  ft/sec
         Reynold's Number in drill pipe =        2,448 LAMINAR
         Reynold's Number in annulus =         624 LAMINAR
         Darcy friction factor = 0.02615
         Prandtl Number = 18.190
         Nusselt Number =       4.36
         Pressure loss in drill pipe =      30.8  psi
         Pressure loss in annulus =     79.7  psi
         Pressure loss in bit =    268.6  psi
         Total Pressure loss in system =     379.1 psi

Hit any key to return to Fluid Rheology menu.
```

Fig. 34 - An example of Bingham plastic fluid loss calculations.

```
Fluid Flow Conditions
11-03-1987 xxx 11:36:26

Fluid model chosen is Power Law

     Average velocity in drill pipe =      2.41  ft/sec
     Average velocity in the annulus =     1.33  ft/sec
     Reynold's Number in drill pipe =       4,318 TURBULENT
     Reynold's Number in annulus =        1,057 LAMINAR
     Darcy friction factor = 0.04571
     Prandtl Number = 18.190
     Nusselt Number =      48.96
     Pressure loss in drill pipe =     259.0  psi
     Pressure loss in annulus =    170.7  psi
     Pressure loss in bit =    268.6  psi
     Total Pressure loss in system =     698.3 psi
     Flow behavior index (n) =  1.136226
     Consistency index (k) =  19.40682

Hit any key to return to Fluid Rheology menu.
```

Fig. 35 - An example of power law fluid loss calculations.

Given the physical geometry of the system being modeled, they are all logical assumptions and the problem is greatly simplified as a result.

However, the last assumption, namely that the fluid properties are independent of temperature, is open to debate. It is evident from Fig. 22 and 23 that the mud specific heat and mud density have a significant effect on the temperature distribution. No investigation was conducted to assess the extent to which these parameters are affected by temperature and until this is done, the validity of this assumption must remain in doubt.

APPLICATION TO FIELD PROBLEMS

The mud circulation temperatures obtained by this method have been used to predict logged bottomhole mud temperatures. Temperatures from the circulation period are used as the initial temperatures for inclusion into a transient line-source solution to predict the transient mud temperature buildup curves[13]. Since the heat flux to the formation is not known with any accuracy, this solution is an approximation of the actual temperature buildup. If we calculate an approximate heat flux by using Eq. 6, the solution of the line-source equation produces a mud temperature at any time mud circulation is stopped. In most cases, where the diameter of the wellbore is less than a foot, the mud temperature is predicted to return, within several hours after mud circulation has ceased, to approximately the temperature of the formation in the vicinity of the wellbore[13].

Data for the 15,000 foot well used in this section to calculate the temperature profiles as shown in Fig. 17 were applied with actual

drill bit size changes made during the drilling of this well. The bottomhole temperatures for the various segments drilled were calculated. These bottomhole temperatures were then used in conjunction with the line-source solution for the temperature buildup after circulation is stopped. The predicted logged bottomhole mud temperatures to be obtained at the time of logging are given in Table 12. The actual bottomhole mud temperature are also presented. Fig. 36 shows good agreement between the calculated and the actual bottomhole mud temperatures. Calculations for other wells have shown similar results, which shows the capability of the model to simulate the apparent physical phenomena[13].

TABLE 12 - CALCULATED AND LOGGED BOTTOMHOLE

TEMPERATURES FOR A 15,000 FOOT GULF COAST WELL

Depth (ft)	Wellbore size (ft)	Logged Bottomhole Mud Temp. (°F)	Calculated Bottomhole Mud Temp. (°F)
7,000	0.771	163	160
10,000	0.508	180	187
11,500	0.508	197	206
12,500	0.350	208	207
14,000	0.350	232	226
15,000	0.350	243	238

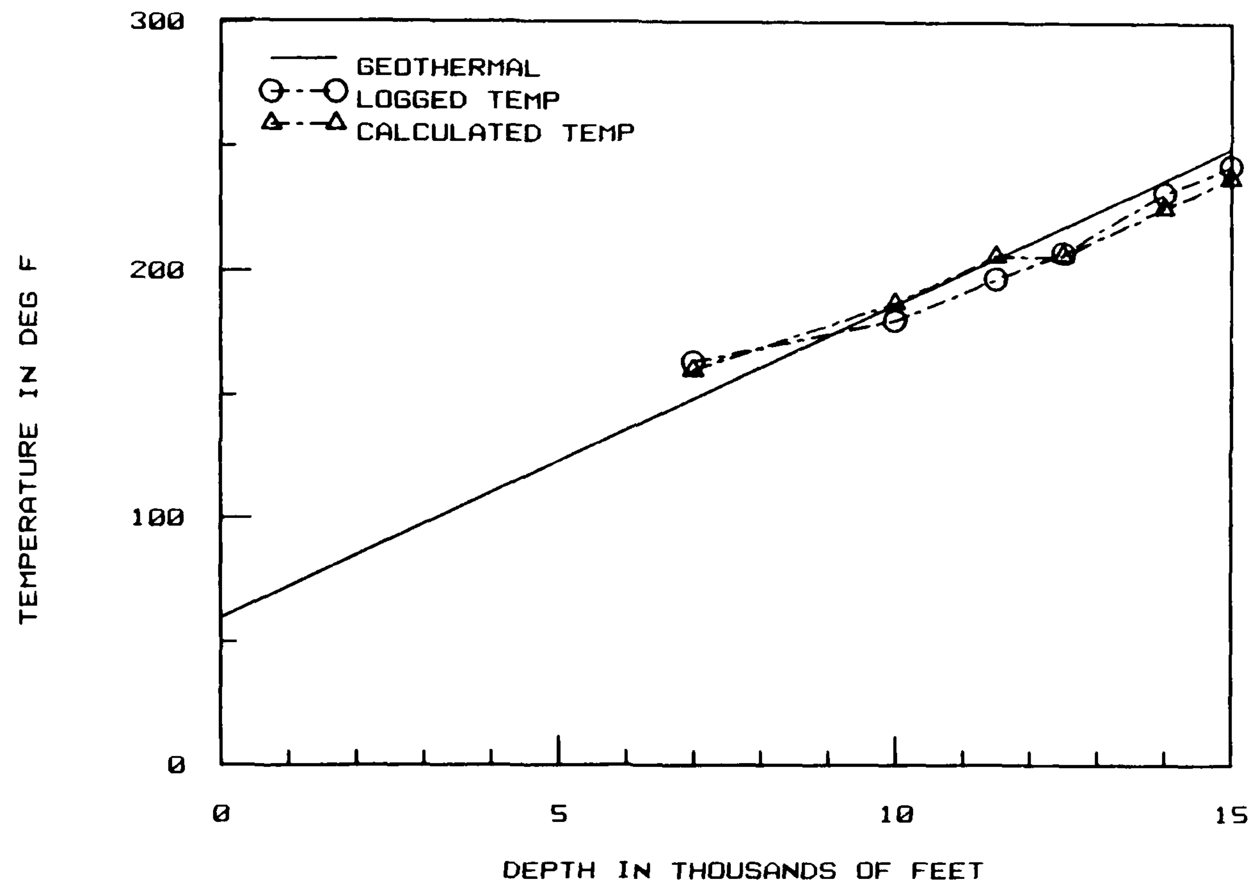


Fig. 36 - Calculated versus logged bottomhole temperature.

CONCLUSIONS

The primary objective of this work was to develop a computer model that estimates the temperature profile in a wellbore both accurately and quickly. This model was then used to investigate the significance of the parameters in terms of their effect on temperature distribution. The major conclusions of this work are as follows:

1. The use of interactive techniques and graphics greatly enhances the effectiveness and user understanding of computer simulation.

2. Although heat transfer and temperature distribution simulation has traditionally been left to those with access to large, high-speed digital computers, the personal computer is well suited for applications in this area.

3. It has been shown that a computer simulation using a steady-state analytical model can be developed to determine circulating mud temperature profiles for the fluids in the drill pipe and in the annulus.

4. This simulator can provide a rapid method for computing mud temperature profiles and bottomhole mud temperatures so that appropriate drilling mud and cement properties can be selected.

5. The simulator has been compared with actual well logging data and has successfully predicted logged bottomhole temperatures.

6. The following parameters have a crucial effect on the wellbore temperature distribution:

   a. drilling fluid flow rate,

b. heat transfer coefficient of the drill pipe,

c. heat transfer coefficient of the annulus,

d. drilling fluid specific heat,

e. drilling fluid density,

f. geothermal gradient,

g. drilling fluid inlet temperature,

h. depth.

7. The simulator has demonstrated that large errors in wellbore temperature estimates can be made if drilling personnel assume that the temperature distribution in the annulus is linear in nature. These errors can range as high as nearly 40°F at the boom of the well, and could have disastrous effects on a drilling mud program or cement job.

NOMENCLATURE

A_A - cross-sectional area of annulus, in^2

A_D - cross-sectional area of drill pipe, in^2

C_1, C_2, C_3, C_4 - Holmes and Swift[13] equation coefficients

C_p - heat capacity of fluid, Btu/(lb-°F)

C_{pf} = heat capacity of formation, Btu/(lb-°F)

D - depth, ft

E - internal energy

f(t) - Ramey's[8] transient heat conduction time function for earth, dimensionless

g - gravitational acceleration, 32.2 ft/sec^2

G - geothermal gradient, °F/ft

g_c - conversion factor, 32.2 ft-lb mass/sec_2-lb force

h_f - wellbore wall heat transfer coefficient, Btu/(ft^2-°F-hr)

h_p - over-all heat transfer coefficient across drill pipe, Btu/(ft^2-°F-hr)

H - enthalpy, Btu/lb mass

J - mechanical equivalent of heat, 778 ft-lb/Btu

K - consistency index, eq. cp

K_1, K_2 - Holmes and Swift[13] integration constants

k_f - formation thermal conductivity, Btu/(ft-°F-hr)

L - total depth of well, ft

m - mass flow rate, lb/hr

n - flow behavior index, dimensionless

p - pressure, lb/in^2

q - Ramey's[8] heat transfer rate, Btu/day

$\dot{Q}_a$ - heat flow in the annulus, Btu/hr

$\dot{Q}_{ap}$ - heat flow across drill pipe, Btu/hr

$\dot{Q}_p$ - heat flow in the drill pipe, Btu/hr

r - radial space variable, in

r_B - borehole radius, in

r_D - drill pipe radius, in

r_2 - outside radius of casing, ft

r_w - wellbore radius, in

T_A - annular temperature, °F

T_D - drill pipe temperature, °F

T_f - formation temperature, °F

T_{Do} - inlet drill pipe temperature, #F

T_{Ha} - bottomhole temperature of fluid in annulus, °F

T_{Hp} - bottomhole temperature of fluid in drill pipe, °F

T_p - drill pipe temperature, °F

T_s - temperature of earth's surface, °F

u - fluid velocity

U - over-all heat transfer coefficient between drill pipe and annulus, BTU/(ft^2-°F-hr)

$\bar{v}$ - average flow rate, ft/sec

V - specific volume

v_A - annular fluid velocity, ft/sec

v_D - drill pipe fluid velocity, ft/sec

w - fluid flow rate, lb/day

W_f - flow work, ft-lb force. lb mass

Z - depth variable, ft

t - time variable, hr

α - thermal diffusivity of earth, sq ft / day

($\alpha = k/\rho c_f$)

Δp - pressure loss, lb/in^2

Δt - time step variable, hr

ΔT - $T_{bottomhole\ fluid} - T_{outlet}$, °F

ρ - fluid density, lb/gal

ρ_f - formation density, lb/ft^3

μ - fluid viscosity, cp

μ_∞ - plastic viscosity, dyne-sec/cm^2

Φ - heat flux to formation, Btu/hr

τ - shear stress, dyne/cm^2

τ_o - yield point, lb/100 ft^2

γ - shear rate, sec^{-1}

REFERENCES

1. Smith, D.K.: *Cementing*, Monograph Series, SPE, Dallas (1976) 4, 81-82.

2. Marshall, D.W. and Bentsen, R.G.: "A Computer Model to Determine the Temperature Distributions in a Wellbore," *J. Can. Pet. Tech.* (January-February 1982) 63-75.

3. Wooley, G.R.: "Computing Downhole Temperatures in Circulation, Injection, and Production Wells," *J. Pet. Tech.* (September 1980) 1509-22.

4. Farris, R.F.: "A Practical Evaluation of Cements for Oil Wells," *Drill. and Prod. Prac.* (1941) 283-92.

5. "Effects of High Pressures and Temperatures on Strength of Oil-well Cements," *Drill. and Prod. Prac.* (1954) 72-81.

6. O'Neal, J.E. and Benischek, H.W.: "The Effects of High Temperatures and Pressures on the Setting Time of Oil-well Cements," *Drill. and Prod. Prac.* (1954) 39-43.

7. Fertl, W.H. and Wichman, P.A.: "How to Determine Static BHT from Well Log Data," *World Oil* (January 1977) 105-106.

8. Ramey, Jr., H.J.: "Wellbore Heat Transmission," *J. Pet. Tech.* (April 1962) 427-35; *Trans.*, AIME, **225**.

9. Edwardson, M.J., Girner, H.M., Parkinson, H.R., Williams, C.D., and Matthews, C.S.: "Calculations of Formation Temperature Disturbances Caused by Mud Circulation," *J. Pet. Tech.* (April 1962) 416-26.

10. Tragesser, A.F., Crawford, P.B., and Crawford, H.R.: "A Method for Calculating Circulating Temperatures," *J. Pet. Tech.* (November 1967) 1507-12.

11. Keller, H.H. and Couch, E.J.: "Well Cooling by Down-Hole Circulation of Water," *Soc. Pet. Eng. J.* (December 1968) 405-12; *Trans.*, AIME, **243**.

12. Raymond, R.L.: "Temperature Distribution in a Circulating Drilling Fluid," *J. Pet. Tech.* (March 1969) 333-41.

13. Holmes, C.S. and Swift, S.C.: "Calculation of Circulating Mud Temperatures," *J. Pet. Tech.* (June 1970) 670-74.

14. Shell, F. and Tragesser, A.: "API is Seeking More Accurate Bottom-Hole Temperatures," *Oil and Gas J.* (July 10, 1972) 72-79.

15. Keller, H.H., Couch, E.J., and Berry, P.M.: "Temperature Distribution in Circulating Mud Columns," *Soc. Pet. Eng. J.* (February 1973) 23-30.

16. Sump, G.D. and Williams, B.B.: "Prediction of Wellbore Temperatures During Mud Circulation and Cementing Operations," ASME paper 73-Pet-6 presented at the 1973 ASME Petroleum Conference, Los Angeles, Sept. 16-20.

17. Oster, C.A. and Scheffler, W.A.: "Well-Hole Temperature Distribution in the Presence of Aquifers, "ASME paper 76-Pet-59 presented at the 1976 Joint Petroleum Mechanical Engineering and Pressure Vessels and Piping Conference, Mexico City, Sep. 19-24.

18. Horne, R.N., and Shinohara, K.: "Wellbore Heat Loss in Production and Injection Wells," *J. Pet. Tech.* (January 1979) 116-18.

19. Cline, D.D.: "A Thermal Analysis of Pseudo-steady Circulating Wellbores," *Research paper SAND81-0241*, Sandia National Laboratories, Albuquerque, New Mexico, 1981.

20. Duda, L.E.: "Computer Simulation of the Cooling Effect Due to Circulation in Four Geothermal Well Models," *Research paper SAND84-1589*, Sandia National Laboratories, Albuquerque, New Mexico, 1984.

21. Corre, B., Eymard, R., and Guenot, A.: "Numerical Computation of Temperature Distribution in a Wellbore While Drilling," paper SPE 13208 presented at the 1984 SPE Annual Technical Conference and Exhibition, Houston, Sept. 16-19.

22. Leutwyler, K. and Bigelow, H.L.: "Temperature Effects on Subsurface Equipment In Steam Injection Systems," *J. Pet. Tech.* (January 1965) 93-101; *Trans.* AIME, 234.

23. Leutwyler, K.: "Casing Temperature Studies in Steam Injection Wells," *J. Pet. Tech.* (September 1966) 1157-62.

24. Dase, W.G. and Heyt, J.W.: "Thermal Protection of Wellbore Casings," ASME paper 72-Pet-1 presented at the 1972 Petroleum Mechanical Engineering and Pressure Vessels & Piping Conference, New Orleans, Sept. 17-21.

25. Incropera, F.P. and DeWitt, D.P.: *Fundamentals of Heat and Mass Transfer*, John Wiley & Sons, New York City (1985).

26. Wark, K.: *Thermodynamics*, McGraw-Hill Book Co., New York City (1983).

27. Lummus, J.L. and Azar, J.J.: *Drilling Fluids Optimization: A Practical Field Approach*, PennWell Publishing Co., Tulsa, OK (1986).

28. Willhite, G.P.: "Over-all Heat Transfer Coefficients in Steam and Hot Water Injection Wells," *J. Pet. Tech.* (May 1967) 607-15.

29. Annis, M.R.: "High-Temperature Flow Properties of Water-Base Drilling Fluids," *J. Pet. Tech.* (August 1967) 1074-80.

30. Ramey, H.J.: "How to Calculate Heat Transmission in Hot Fluid Injection," *Pet. Eng.* (November 1964) 110-20.

31. van Everdingen, A.F., and Hurst, W.: "The Application of the LaPlace Transformation to Flow Problems in Reservoirs," *Trans.* AIME (1949) **186**, 305-24.

32. Moss, J.T. and White, P.D.: "How to Calculate Temperature Profiles in a Water-Injection Well," *Oil and Gas J.* (March 9, 1959) 174-78.

33. Carslaw, H.S. and Jaeger, J.C.: *Conduction of Heat in Solids*, Oxford U. Press, Amen House, London (1959).

34. van Everdingen, A.F.: "The Skin Effect and Its Influence on the Productivity Capacity of a Well", *Trans.* AIME (1953) **198**, 171.

35. Bourgoyne, Jr., A.T., Millheim, K.K., Chenevert,M.E. and Young, Jr., F.S.: *Applied Drilling Engineering*, Textbook Series, SPE, Dallas (1986), **2**, 131-55.

36. Bannister, C.E.: "Rheological Evaluation of Cement Slurries: Methods and Models," paper SPE 9284 presented at the 1980 SPE Annual Technical Conference and Exhibition, Dallas, Sept. 21-24.

37. *Theory and Application of Drilling Fluid Hydraulics*, Alun Whittaker (ed.), International Human Resources Development Center, Boston, 16-22.

38. Chilingararian, G.V. and Vorabutr, P.: *Drilling and Drilling Fluids*, Elsevier Scientific Publishing Co., Amsterdam (1981) 271-94.

39. Cloud, J.E. and Clark, P.E.: "Stimulation Fluid Rheology III: Alternatives to the Power Law Model for Cross-Linked Fluids," paper SPE 9332 presented at the 1980 SPE Annual Technical Conference and Exhibition, Dallas, Sept. 21-24.

SUPPLEMENTAL SOURCES CONSULTED

1. Nowak, T.J.: "The Estimation of Water Injection Profiles from Temperature Surveys," *Trans.* AIME (1953) **198**, 203-12.

2. Fertl, W.H. and Wichmann, P.A.: "How to Determine Static BHT from Well Log Data," *World Oil* (January 1977) 105-6.

3. Lesem, L.B., Greytok, F., Marotta, F., and McKetta, Jr., J.J.: "A Method of Calculating the Distribution of Temperature in Flowing Gas Wells," *Trans.* AIME (1957) **210**, 169-76.

4. Squier, D.P., Smith, D.D., Dougherty, E.L.: "Calculated Temperature Behavior of Hot-Water Injection Wells," *J. Pet. Tech.* (April 1962) 436-40.

5. Satter, A.: "Heat Losses During Flow of Steam Down a Wellbore," *J. Pet. Tech.* (July 1965) 845-51; *Trans.* AIME, **234**.

6. Eickmeier, J.R., Ersoy, D., and Ramey, Jr., H.J.: "Wellbore Temperatures and Heat Losses During Production or Injection Operations," *J. Cdn. Pet. Tech.* (April-June 1970) 115-21.

7. Couch, E.J., Keller, H.H., and Watts, J.W.: "Permafrost Thawing Around Producing Oil Wells," *J. Cdn. Pet. Tech.* (April-June 1970) 107-11.

8. Kazemi, H. and Perkins, T.K.: "A Mathematical Model of Thaw-Freeze Cycles Beneath Drilling Rigs and Production Platforms in Cold Regions," *J. Pet. Tech.* (March 1971) 381-90.

9. Pacheco, E.F. and Farouq Ali, S.M.: "Wellbore Heat Losses and Pressure Drop in Stream Injection," *J. Pet. Tech.* (February 1972) 139-44.

10. Landry, B., Curry, D.M., and Cox, J.E.: "Disposal of Thermal/Radioactive Wastes in Permafrost Ground Areas," ASME paper 73-WA/HT-8 presented at the 1973 ASME Winter Annual Meeting, Detroit, Nov. 11-15.

11. Pui, N.K. and Kljucec, N.M.: "Permafrost Melting Predictions Match Logs," *Oil and Gas J.* (August 15, 1977) 66-70.

12. Farouq Ali, S.M.: "A Comprehensive Wellbore Steam/Water Flow Model for Steam Injection and Geothermal Applications," *Soc. Pet. Eng. J.* (October 1981) 527-34.

13. Sekiguchi, K.: "A Method for Determining Terrestrial Heat Flow in Oil Basinal Areas," *Techtonophysics*, 103 (1984) 67-79.

14. Pruess, K. and Narasimhan, T.N.: "A Practical Method for Modeling Fluid and Heat Flow in Fractured Porous Media," *Soc. Pet. Eng. J.* (February 1985) 14-26.

15. Rubin, B. and Buchanan, W.L.: "A General Purpose Thermal Model," *Soc. Pet. Eng. J.* (April 1985) 202-14.

16. O'Sullivan, M.J., Bodvarsson, G.S., Pruess, K., and Blakeley, M.R.: "Fluid and Heat Flow In Gas-Rich Geothermal Reservoirs," *Soc. Pet. Eng. J.* (April 1985) 215-26.

17. Durrant, A.J. and Thambynayagam, R.K.M.: "Wellbore Heat Transmission and Pressure Drop for Steam/Water Injection and Geothermal Production: A Simple Solution Technique," *SPE Res. Eng.* (March 1986) 148-162.

18. Sammon, P.H. and Rubin, B.: "Practical Control of Timestep Selection in Thermal Simulation," *SPE Res. Eng.* (March 1986) 163-70.

19. *Handbook of Heat and Mass Transfer, Volume 1: Heat Transfer Operations*, N.P. Cheremisinoff (ed.), Gulf Publishing Co., Houston (1986).

20. "Heat Flow to Refrigeration Borehole," Gulf Mineral Resources Co., Denver (March 1980) 6-8.

21. McAdams, W.H.: *Heat Transmission*, second edition, McGraw-Hill Book Company, Inc., New York City (1954).

22. Gosse, J.: *Technical Guide to Thermal Processes*, Cambridge University Press, Cambridge (1986).

23. *Drilling Mud and Cement Slurry Rheology Manual*, Gulf Publishing Co., Houston (1982).

24. Vacquier, V.: "Oil Fields - A Source of Heat Flow Data," *Tectonophysics*, 103 (1984) 81-98.

25. Hanks, R.W.: "The Laminar-Turbulent Transition for Flow in Pipes, Concentric Annuli, and Parallel Plates," *A.I.Ch.E. J.* (January 1963) 45-48.

26. Stacey, F.D.: *Physics of the Earth*, John Wiley & Sons, New York City (1977).

27. Swanson, S.R., Sandquist, G.M., and Kunze, J.F.: "Forced Convective Heat Transfer in Porous Media with Small Biot Number", ASME paper 77-HT-96 presented at the 1977 AIChE-ASME Heat Transfer Conference, Salt Lake City, Aug. 15-17.

28. Fukuda, M., Culver, G.G., Kreitlow, D.B., and Reistad, G.M.: "Natural Convection Heat Transfer Models for Downhole Heat Exchanger Applications in Shallow Geothermal Systems," ASME paper 77-HT-55 presented at the 1977 AIChE-ASME Heat Transfer Conference, Salt Lake City, Aug. 15-17.

29. Kunze, J.F., Stoker, R.C., and Goldman, D.: "Heat Transfer in Formation as a Geothermal Reservoir Engineering Tool," ASME paper 77-HT-88 presented at the 1977 AIChE-ASME Heat Transfer Conference, Salt Lake City, Aug. 15-17.

30. Sieder, E.N. and Tate, G.E.: "Heat Transfer and Pressure Drop of Liquids in Tubes," *Ind. & Engr. Chem.* (1936) **28**, 1429-35.

31. *Handbook of Heat Transfer*, W.M. Rohsenow and J.P. Hartnett (ed.), McGraw-Hill Book Co., New York City (1973).

32. Lienhard, J.H.: *A Heat Transfer Textbook*, Prentice-Hall Inc., Englewood Cliffs, NJ (1981).

33. Ingersoll, L.R., Zobel, O.J., and Ingersoll, A.C.: *Heat Conduction*, The University of Wisconsin Press, Madison (1954).

34. Ingersoll, L.R., Zobel, O.J., and Ingersoll, A.C.: *Heat Conduction*, McGraw-Hill Book Company, Inc., New York City (1948).

35. Soloukhin, R.I. and Afgan, N.H.: *Measurement Techniques in Heat and Mass Transfer*, Hemisphere Publishing Corp., Washington (1985).

36. Goldstone, T.W.: "Heat Transfer to Fluid Flowing in Annuli of Various Cross-sectional Geometries," MS thesis, Texas A&M U., College Station, TX (1962).

37. Logan, Jr., E.: "Heat Transfer to a Fluid Flowing in an Annulus," MS thesis, Texas A&M U., College Station, TX (1958).

38. *Heat Transfer in Enclosures*, R.W. Douglass and A.F. Emery (ed.), The American Society of Mechanical Engineers, New York City (1984).

39. *Numerical Methods in Heat Transfer*, J.L.S. Chen and K. Vafai (ed.), The American Society of Mechanical Engineers, New York City (1986).

40. Aziz, A. and Na, T.Y.: *Perturbation Methods in Heat Transfer*, Hemisphere Publishing Corp., Washington (1984).

41. *Numerical Properties and Methodologies in Heat Transfer*, T.M. Shih (ed.), Hemisphere Publishing Corp., Washington (1983).

42. *Convective Heat Transfer in Two-Phase and One-Phase Flows*, V.M. Borishanskii and I.I. Paleev (ed.), Israel Program for Scientific Translations, Ltd., Jerusalem (1969).

43. Gosman, A.D., Launder, B.E., and Reece, G.J.: *Computer-Aided Engineering: Heat Transfer and Fluid Flow*, Ellis Horwood, Ltd., Chichester, England (1985).

44. *Advances in Heat Transfer*, J.P. Hartnett and T.F. Irvine, Jr. (ed.), Vol. 6, Academic Press, New York City (1970).

45. *Advances in Heat Transfer*, J.P. Hartnett and T.F. Irvine, Jr. (ed.), Vol. 15, Academic Press, New York City (1982).

46. Perkins, T.K., Rochon,J.A., and Knowles, C.R.: "Studies of Pressures Generated Upon Refreezing of Thawed Permafrost Around a Wellbore," *J. Pet. Tech.* (October 1974) 1159-66.

47. Richardson, J.G. and Blackwell, R.J.: "Use of Simple Mathematical Models for Predicting Reservoir Behavior," *J. Pet. Tech.* (September 1971) 1145-54.

48. Juvkam-Wold, H.C.: "Spray-Ice Islands Evaluated for Arctic-Drilling Structures," *Oil and Gas J.* (April 21, 1986) 57-66.

49. Goodman, M.A.: "Temperature Histories in Geothermal Wells: Survey of Rock Thermomechanical Properties and Drilling, Production, and Injection Case Studies," *Research paper SAND81-7128*, Sandia National Laboratories, Albuquerque, New Mexico, 1981.

50. Ashworth, E.: "The Applications of Finite Element Analysis to Thermal Conductivity Measurements," MS thesis, South Dakota School of Mines and Technology, Rapid City, SD (1983).

51. Barden,Jr., W.: *Color Computer Graphics*, Tandy Corporation, Fort Worth, TX (1982).

52. Hearn, D. and Baker, M.P.: *Microcomputer Graphics*, Prentice-Hall, Inc., Englewood Cliffs, NJ (1983).

53. Weinstock, N.: *Computer Animation*, Addison-Wesley Publishing Company, Inc., Reading, Massachusetts (1986).

54. Chapra, S.C. and Canale, R.P.: *Introduction to Computing for Engineers*, McGraw-Hill Book Company, New York City (1986).

55. Rob, P.: *Programming the IBM PC: Big Blue BASIC*, Wadsworth Publishing Company, Belmont, California (1985).

56. Park, C.S.: *Interactive Microcomputer Graphics*, Addison-Wesley Publishing Company, Inc., Reading, Massachusetts (1985).

57. Guggenheim, E.A.: *Thermodynamics*, Elsevier Science Publishing Company, Inc., New York City (1986),

58. Brush, S.G.: *The Kind of Motion We Call Heat*, Elsevier Science Publishing Company., New York City (1986).

APPENDIX A

MATHEMATICAL MODEL AND TREATMENT

Discussion of Mathematical Model

The circulation of fluid during the drilling operation has been represented schematically in Fig. 1, and the process of circulation has been separated into three well-defined phases[12]: (1) fluid enters the drill pipe at the surface and passes down the drill string; (2) fluid exits the drill string through the nozzles in the drill bit and enters the annulus at the bottom; and (3) fluid passes up the annulus and exits at the surface.

The following assumptions were made by Raymond[12] to obtain the desired differential equations:

1. Axial conduction of heat in the fluid is insignificant compared with axial convection. This appears to be an excellent assumption considering what normal circulation rates are experienced in the circulation of drilling fluids.

2. There are no radial gradients in the fluids in either the drill string or the annulus. Since it is assumed that the fluid in the drill pipe is in turbulent flow and well mixed every 30 feet in the annulus because of the presences of tool joints and drill collars, this is also an excellent assumption.

3. The properties of the fluid, such as heat capacity, density, and thermal conductivity, do not change significantly with increases in temperature.

4. Heat generation by viscous dissipation in the fluid is negligible.

In the first phase, the fluid enters the drill pipe at a specified temperature, T_{Do}. As the fluid passes down the pipe, its temperature is determined by the rates at which (1) heat is convected down the drill pipe, (2) heat is exchanged between the drill pipe and the annulus, and (3) the temperature of the drill-pipe fluid changes with time. Consequently, the equation that describes the temperature of the fluid in the drill pipe as a function of time, t, and depth, Z, is

$$A_D \rho v_D C_p \frac{\delta T_D(Z,t)}{\delta Z} + 2\pi r_D U[T_D(Z,t) - T_A(Z,t)] = -\rho A_D C_p \frac{\delta T_D(Z,t)}{\delta t} \quad . \ . \ . \ . \ . \ . \ . \ . \quad (A\text{-}1)$$

In Eq. A-1, it has been assumed that the over-all heat transfer coefficient, U, is independent of depth and time. Since it has already been assumed that the fluid thermal properties are independent of temperature, this is a good assumption. The second phase of the circulating process simply requires that the fluid temperature at the exit of the drill pipe be the same as the temperature at the entrance of the annulus; i.e., $T_D(L,t) = T_A(L,t)$. Accordingly, in the third phase, the drilling fluid enters the annulus at a temperature of $T_D(L,t)$. As the fluid is pumped up the annulus, it temperature is

determined by the rates at which (1) heat is convected up the annulus, (2) heat is exchanged between the annulus and the drill pipe, (3) heat is exchanged between the formation adjacent to the annulus and the fluid in the annulus, and (4) the temperature of the annular fluid changes with time. Consequently, the equation that describes the temperature of the fluid in the annulus as a function of t and Z is

$$A_A \rho v_A C_p \frac{\delta T_A(Z,t)}{\delta Z} + 2\pi r_D U[T_D(Z,t) - T_A(Z,t)] + 2\pi r_B h_f[T_f(r_w,Z,t) - T_A(Z,t)] = \rho A_D C_p \frac{\delta T_A(Z,t)}{\delta t} \quad \text{. . . . . . . (A-2)}$$

Since the thermal conductivity of the formation adjacent to the wellbore is small, it will be assumed that there is no transfer of heat by conduction in the vertical direction in the formation. Hence, the formation temperature $T_f(r_w,Z,t)$ is regulated by the radial diffusivity equation

$$\frac{\delta T_f(r_w,Z,t)}{\delta t} = \frac{k_f}{\rho_f C_{pf}} \frac{1}{r} \frac{\delta}{\delta r}\left[r \frac{\delta T_f(r_w,Z,t)}{\delta r}\right] \quad \text{. . . . . . . (A-3)}$$

Eq. A-3 is coupled with Eq. A-2 through the rate of heat transfer between the fluid in the annulus and the formation. This requires that the flux of heat out of the formation be the same as the flux of the heat into the annulus; that is, at any depth Z,

$$2\pi r_B h_f[T_f(Z,t) - T_A(Z,t)] =$$

$$2\pi r_B k_f \left[\frac{\delta T_f(r_w,Z,t)}{\delta r}\right]_{r = r_B} \quad \ldots\ldots\ldots\ldots \quad (A\text{-}4)$$

Thus, the temperature profiles in the drill pipe, annulus, and formation can be obtained by solving Eqs. A-1 through A-3, with the additional requirement specified by Eq. A-4 once appropriate initial and boundary conditions are specified.

APPENDIX B

DERIVATION OF RAMEY'S[8]

WELLBORE HEAT TRANSMISSION SOLUTION

In 1962, Ramey considered the injection of a fluid down the tubing in a well which is cased to the top of the injection interval. Assuming that the fluid is injected at known injection rates and temperatures, he determined the temperature of the injected fluid as a function of depth and time. Fig. B-1 presents a schematic illustration of the problem. As shown on Fig. B-1, W lb/day of fluid is injected in the tubing at the surface at a temperature of T_o. The inside radius of the tubing is r_1, and the temperature T_1 of the fluid in the tubing is a function of both depth Z and t. The outside radius of the casing is r'_2, and the temperature of the casing outer surface is T_2, also a function of depth and time.

The usual solution procedure for flow problems of this type is to solve the total energy and mechanical energy equations simultaneously to produce both temperature and pressure distributions. However, the solution may be approximated by the following considerations. The total energy equation is

$$dH - \frac{g\,dZ}{g_c J} + \frac{u\,du}{g_c J} - dQ - \frac{dW_f}{J} \quad \text{(B-1)}$$

Assuming steady flow of a single phase fluid in a pipe, flow-work W_f is zero and Eq. B-1 becomes

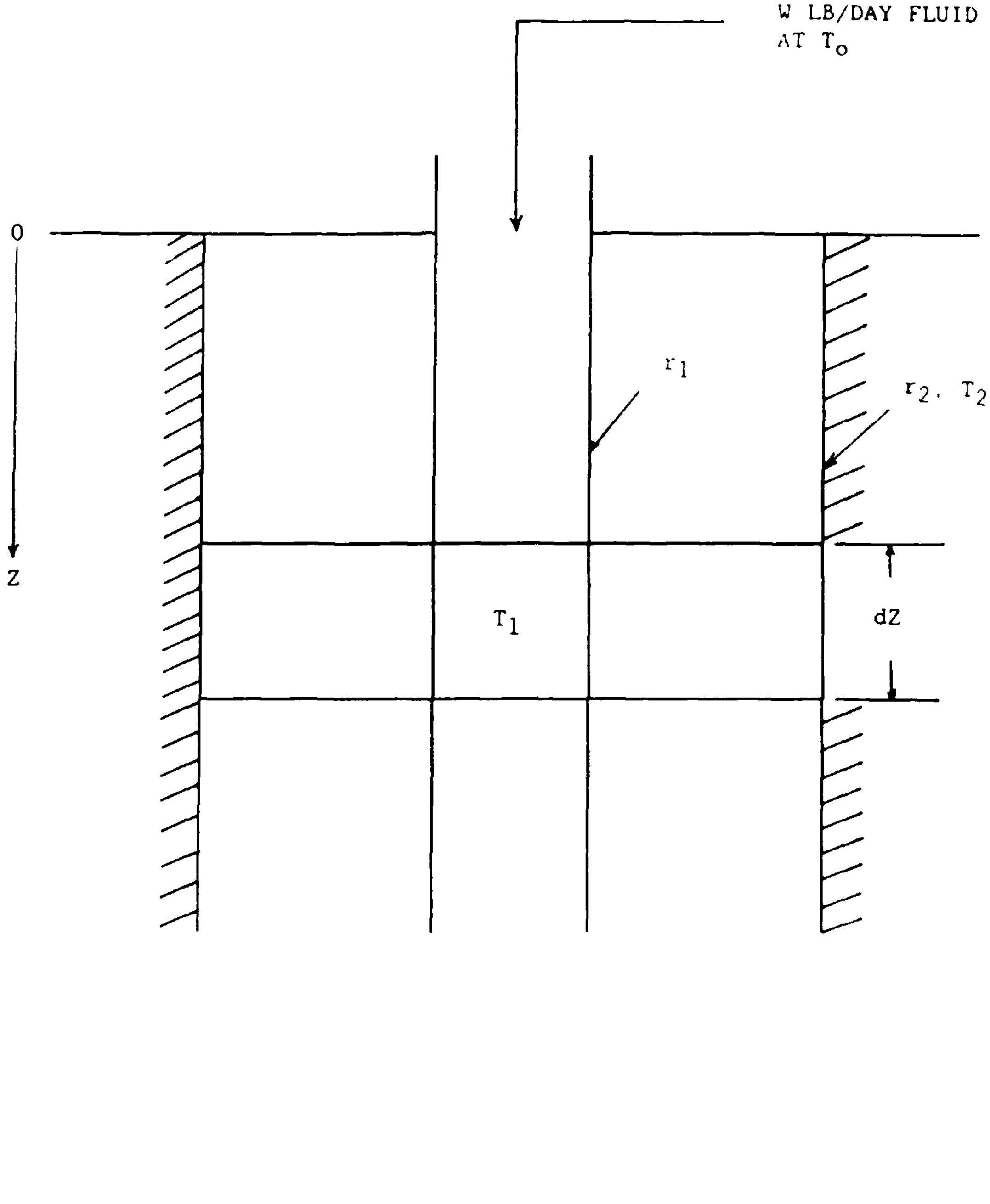


Fig. B-1 - Diagram for the derivation of the wellbore heat problem

$$dH = \frac{g\ dZ}{g_c J} + \frac{u\ du}{g_c J} = dQ \quad \text{(B-2)}$$

If it is assumed that the fluid flowing is an incompressible liquid, the kinetic energy term becomes zero. Thus,

$$dH + \frac{g\ dZ}{g_c\ J} = dQ \quad \text{(B-3)}$$

But by definition, enthalpy is

$$dH = dE + \frac{d(PV)}{J} = dE + \frac{V\ dp}{J} \quad \text{(B-4)}$$

for an incompressible liquid. Or

$$dH = cdT + \frac{V\ dP}{J} \quad \text{(B-5)}$$

Neglecting the flowing friction, the V dP term is equal to the change in fluid head, and the change in enthalpy is

$$dH \approx cdT + \frac{g\ dZ}{J} \quad \text{(B-6)}$$

Considering flow down the well, the increase in enthalpy due to increase in pressure is approximately equal to the loss in potential energy. Conversely, for flow up the well, the loss in enthalpy due to

the decrease in pressure is approximately equal to the increase in potential energy. As a result, the total energy equation becomes

$$cdT \approx dQ \qquad \text{(B-7)}$$

for an incompressible liquid flowing vertically in a tube of constant diameter.

Assuming that no phase changes occur, an approximate energy balance over the differential element of depth, dZ, yields: heat lost by the liquid = heat transferred to the casing, or

$$dq = -WcdT_1 = 2\pi r_1 U(T_1 - T_2)dZ \qquad \text{(B-8)}$$

The rate of heat conduction from the casing to the surrounding formation may be expressed as

$$dq = \frac{2\pi k(T_2 - T_c)dZ}{f(t)} \qquad \text{(B-9)}$$

Eq. B-9 implies the assumption that heat transfers radially away from the wellbore. The time function f(t) depends on the conditions specified for heat conduction and will be discussed later. Assuming the geothermal temperature is a linear function[12] of depth,

---

[12] It is not necessary that geothermal temperature be linear with depth. Solutions may also be obtained if geothermal temperature is represented graphically as a function of depth.

$$T_e = aZ + b \quad \text{(B-10)}$$

Eqs. B-9 and B-10 can be substituted into Eq. B-8 to produce

$$\frac{\delta T_1}{\delta Z} + \frac{T_1}{A} - \frac{(aZ + b)}{A} = 0,\ A \neq 0 \quad \text{(B-11)}$$

and

$$A = \frac{Wc[k + r_1 U f(t)]}{2\pi r_1 U k} \quad \text{(B-12)}$$

An integrating factor for Eq. B-11 is $e^{Z/A}$. Thus,

$$T_1 e^{Z/A} = \int \frac{(aZ + b)e^{Z/A}}{A} dZ + C(t) \quad \text{(B-13)}$$

or

$$T_1 e^{Z/A} = (AZ - aA + b)e^{Z/A} + C(t) \quad \text{(B-14)}$$

or

$$T_1(Z,t) = aZ - aA + b + C(t)e^{-Z/A} \quad \text{(B-15)}$$

The function C(t) can be evaluated from the condition that $T_1 = T_o$ for

$Z = 0$. Thus,

$$C(t) = T_o(t) + aA - b \quad \text{(B-16)}$$

And the final expression for liquid temperature as a function of depth and time is

$$T_1(Z,t) = aZ + b - aA + [T_o(t) + aA - b]e^{-Z/A} \quad \text{(B-17)}$$

To apply Eq. B-17, it is necessary to evaluate the time function, f(t). Eq. B-9 can be rearranged to

$$f(t) = \frac{2\pi k(T_2 - T_c)}{dq/dZ} \quad \text{(B-9a)}$$

which is the definition of this time function. In this form, it is clear that the function f(t) has the same relationship to transient heat flow from a wellbore that the van Everdingen-Hurst[31] constant flux P(t) function has to transient fluid flow. In the case of the general wellbore heat transfer problem, neither heat flux nor temperature at the wellbore remains constant except in special cases. A semi-rigorous treatment of transient heat conduction would involve a complex superposition at each depth. Thus, we wish to find approximate values of f(t) which will provide engineering accuracy. Success will be determined by comparison of calculated temperatures with measured field temperatures.

Fortunately, many solutions[8] to transient heat and fluid flow problems exist which may be used to estimate f(t). For example, the Moss and White[32] wellbore heat transmission solution assumes that transient heat conduction to the earth can be represented by a line source losing heat at constant flux. Carslaw and Jaeger[33] present graphical and analytical solutions for the cases of internal cylindrical sources losing heat at constant flux, constant temperature, and under the radiation boundary condition. Fig. B-2 presents Ramey's time function for several different internal boundary conditions. As can be seen from Fig. B-2, the solutions presented converge at long tines (about one week or more). This is completely analogous to pressure build-up theory that at sufficiently long times pressure is controlled by formation conditions.[8] For times less than a dimensionless time of 1,000 (i.e., $\alpha t/r_2'^2 = 1000$), the radiation boundary condition has been found to produce logical values for f(t). The radiation inner boundary conditions is

$$-k\left(\frac{\delta T}{\delta r}\right)_{r=r_2'} = U_2(T_1 - T_2) \qquad \text{(B-18)}$$

where $U_2 = r_1 U/r_2'$. This boundary condition is comparable to the van Everdingen[34] skin effect, also well known in pressure build-up theory. Physically, Eq. B-18 states that heat flow in the annular region between r_1 and r_2' is controlled by steady-state convection, rather than conduction.

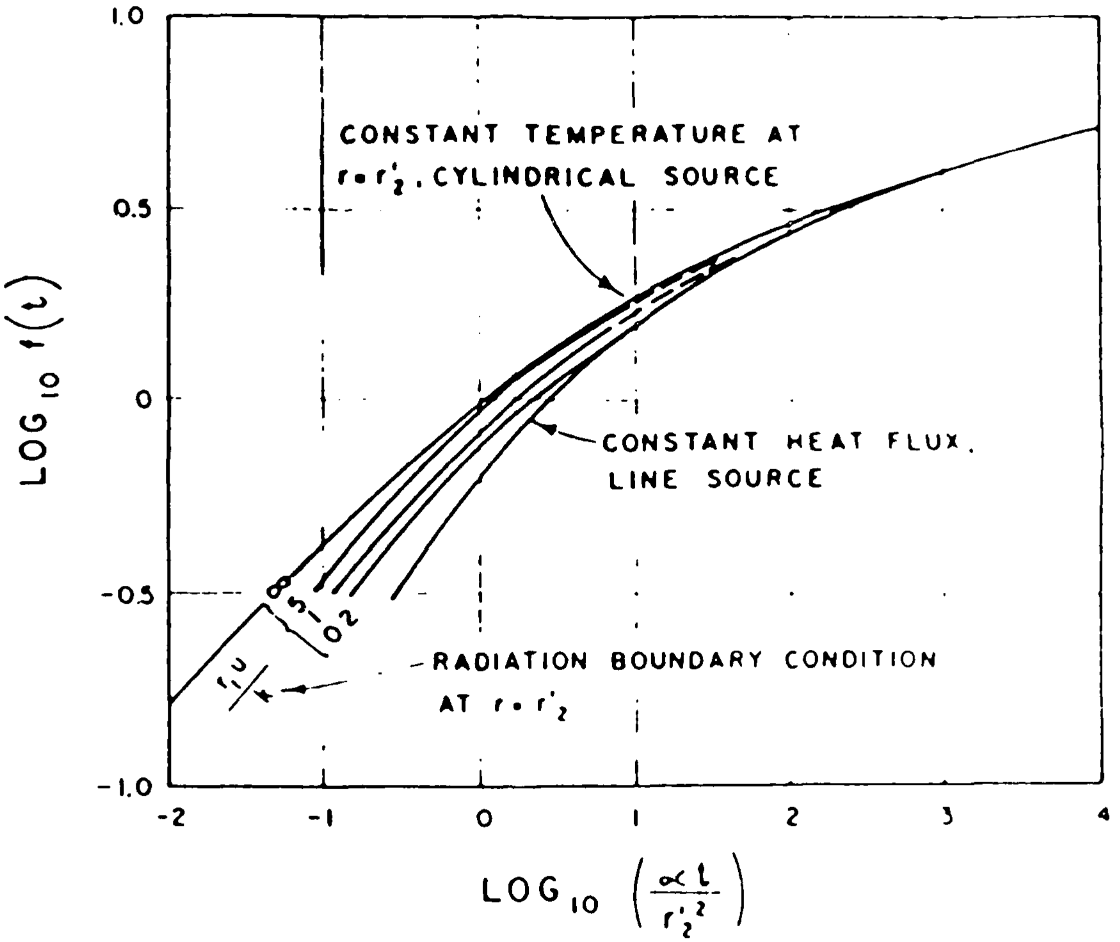


Figure B-2 - Ramey's[8] transient conduction plot.

The solution for this case is presented by Carslaw and Jaeger[33] and is reproduced on Fig. B-2. The time function is seen to depend upon (r_1U/k). However, the radiation boundary case does not depend strongly upon (r_1U/k) and the solution to this case approaches that of the constant-temperature cylindrical source as (r_1U/k) approaches infinity. Thus, the constant-temperature cylindrical-source solution is the recommended solution if thermal resistance in the wellbore is negligible. For times greater than those shown on Fig. B-2, the line source solution as given by Eq. 23 is recommended.

ASSOCIATED HEAT PROBLEMS

The solution presented by Eqs. 25 and 26 also applies to wellbore heat problems other than injection down tubing. For example, injection down casing may be handled by computing the over-all coefficient including only the film coefficient at the casing wall. Wellbore temperatures in a flowing well may be computed if the depth scale is referenced to the producing interval. Thus, $T_o(t)$ becomes the producing formation temperature, and geothermal temperature should be expressed as a function of distance above the producing interval.

Other wellbore heat problems can be solved approximately by methods similar to those used for Eq. 25. That is, write heat balances over each flowing stream in the wellbore and assume that heat loss from the wellbore may be represented by Eq. B-9. If two or more flowing streams are involved, the result will be a higher-order differential equation than Eq. B-11. Temperatures in each stream may be determined, if desired. Note that Eqs. B-8, B-9, and B-10 could

have been solved for T_2, the casing temperature. This problem may have significance in interpretation of temperatures measured in the annulus when fluid is flowing in the tubing.

APPENDIX C

RHEOLOGICAL PRESSURE LOSS MODEL CALCULATIONS

LAMINAR FLOW IN DRILL PIPE AND ANNULI

The drilling engineer deals primarily with the flow of drilling fluids down the circular wellbore of the drill string and up the circular annular space between the drill string and the casing of the open hole[35]. If the pumping rate of the drilling rig's mud pumps is low enough for the flow to be laminar, the Newtonian, Bingham Plastic, or power law model can be employed to develop the mathematical relation between flow rate and frictional pressure drop. In this development, the following simplifying assumptions are made[35]:

1. the drill string is placed concentrically in the casing or open hole,
2. the drill string is not being rotated,
3. sections of open hole are of circular shape and of known diameter,
4. the drilling fluid is incompressible, and
5. the flow is isothermal.

In actuality, none of the above simplifying assumptions are completely valid[35], and the resulting system of equations will not perfectly describe the laminar flow of drilling fluids in the well. Also note that the three rheological models listed at the outset do not take into account the thixotropic nature of drilling mud and only approximate the actual laminar flow fluid behavior.

TURBULENT FLOW IN DRILL PIPE AND ANNULI

In many drilling operations, the drilling fluid is pumped at a rate which is too high for laminar flow to be maintained. The fluid laminae become unstable and break into a chaotic diffused flow pattern[38]. The transfer of momentum caused by this disorganized fluid movement causes the velocity distribution to become more uniform across the center portion of the pipe than for laminar flow. However, a thin boundary layer of fluid near the pipe walls generally remains in laminar flow.

A mathematical development of flow equations for turbulent flow has not been possible to date[38]. However, a large amount of experimental work has been done in straight sections of circular pipe, and the factors influencing the onset of turbulent flow and the frictional pressure losses due to turbulent flow have been identified. By applying the method of dimensional analysis, these factors have been grouped so that the empirical data could be expressed in terms of dimensionless numbers. The onset of turbulence is associated with the existence of random fluctuations in the fluid, and at least on a small scale, the flow is inherently unsteady[25]. The existence of turbulent flow can be advantageous in the sense of providing increased heat and mass transfer rates. However, the motion is extremely complicated and difficult to describe theoretically.

For engineering purposes, flow of a Newtonian fluid in pipes usually is considered to be laminar if the Reynolds number is less

than 2,100 and turbulent if the Reynolds number is greater than 2,100. However, for Reynolds numbers of about 2,000 to 4,000, the flow of most drilling fluids is literally in a transition region between laminar flow and fully developed turbulent flow.

SUMMARY OF FRICTIONAL PRESSURE LOSS EQUATIONS[38]

Newtonian Fluid Model

Mean Velocity, $\bar{v}$

Pipe

$$\bar{v} = q/2.448d^2$$

Annulus

$$\bar{v} = q/2.448(d_2^2 - d_1^2)$$

Flow Behavior Parameters

$$\mu = \theta_{300}$$

Turbulence Criteria

Pipe

$$N_{Rec} = 2,100$$

$$N_{Re} = 928\rho\bar{v}d/\mu$$

Annulus

$$N_{Rec} = 2,100$$

$$N_{Re} = 757\rho\bar{v}(d_2 - d_1)/\mu$$

Laminar Flow Frictional Pressure Loss

Pipe

$$\frac{dp_f}{dL} = \frac{\mu\bar{v}}{1500d^2}$$

Annulus

$$\frac{dp_f}{dL} = \frac{\mu\bar{v}}{1000(d_2 - d_1)^2}$$

Turbulent Flow Frictional Pressure Loss

Pipe

$$\frac{dp_f}{dL} = \frac{\rho^{0.75}\bar{v}^{1.75}\mu^{0.25}}{1800d^{1.25}}$$

Annulus

$$\frac{dp_f}{dL} = \frac{\rho^{0.75}\bar{v}^{1.75}\mu^{0.25}}{1396(d_2 - d_1)^{1.25}}$$

Bingham Plastic Model

Mean Velocity, $\bar{v}$

Pipe

$$\bar{v} = q/2.448d^2$$

Annulus

$$\bar{v} = q/2.448(d_2^2 - d_1^2)$$

Flow Behavior Parameters

$$\mu_p = \theta_{600} - \theta_{300}$$

Turbulence Criteria

Pipe

$$N_{He} = 37{,}100\rho\tau_y d^2/\mu_p^2$$

N_{Rec} from Fig. 4.33[38]

$$N_{Re} = 928\rho\bar{v}d/\mu_p$$

Annulus

$$N_{He} = 24{,}700\rho\tau_y(d_2 - d_1)^2/\mu_p^2$$

$$N_{Re} = 757\rho\bar{v}(d_2 - d_1)/\mu_p$$

Laminar Flow
Frictional
Pressure Loss

Pipe

$$\frac{dp_f}{dL} = \frac{\mu_p \bar{v}}{1500d^2} + \frac{\tau_y}{225d}$$

Annulus

$$\frac{dp_f}{dL} = \frac{\mu_p \bar{v}}{1000(d_2 - d_1)^2} + \frac{\tau_y}{200(d_2 - d_1)}$$

Turbulent Flow
Frictional
Pressure Loss

Pipe

$$\frac{dp_f}{dL} = \frac{\rho^{0.75} \bar{v}^{1.75} \mu_p^{0.25}}{1800d^{1.25}}$$

Annulus

$$\frac{dp_f}{dL} = \frac{\rho^{0.75} \bar{v}^{1.75} \mu_p^{0.25}}{1396(d_2 - d_1)^{1.25}}$$

Power - Law Model

Mean Velocity, $\bar{v}$

Pipe

$$\bar{v} = q/2.448d^2$$

Annulus

$$\bar{v} = q/2.448d^2$$

Flow Behavior
Parameters

$$n = 3.32 \log(\theta_{600}/\theta_{300})$$

$$K = \frac{510\ \theta_{300}}{511^n}$$

Turbulence Criteria

Pipe

N_{Rec} from Fig. 4.34[38]

$$N_{Re} = \frac{89,100\ \rho(\bar{v})^{2-n}}{K} \left(\frac{0.0416d}{3+1/n}\right)$$

Annulus

$$N_{Re} = \frac{109,000\ \rho(\bar{v})^{2-n}}{K} \left[\frac{0.0208(d_2 - d_1)}{2 + 1/n}\right]^n$$

Laminar Flow Frictional Pressure Loss

Pipe

$$dp_f = \frac{K\bar{v}^n \left(\frac{3 + 1/N}{0.0416}\right)}{144,000\ d^{1+n}}$$

Annulus

$$dp_f = \frac{K\bar{v}^n \left(\frac{3 + 1/N}{0.0416}\right)}{144,000\ d^{1+n}}$$

Turbulent Flow Frictional pressure Loss

Pipe

$$\frac{dp_f}{dL} = \frac{f\rho\bar{v}^2}{25.8d}$$

Annulus

$$\frac{dp_f}{dL} = \frac{f\rho\bar{v}^2}{21.1(d_2 - d_1)}$$

APPENDIX D

OVER-ALL HEAT TRANSFER COEFFICIENT

The steady-state rate of heat flow through a wellbore Q Btu/hour is proportional to the temperature difference between the fluid and the formation, and the cross-sectional area perpendicular to the direction of heat flow[28]. This factor of proportionality, which is called the over-all heat transfer coefficient, represents the net resistance of the flowing fluid, tubing, casing annulus, casing wall, and cement sheath to the flow of heat. Hence, we can write

$$Q = U_j A_j \Delta T_j \quad \text{(D-1)}$$

Eq. D-1 defines U, the over-all heat transfer coefficient based on the characteristic area A and a characteristic temperature difference ΔT. The subscript j in Eq. D-1 defines the surface area upon which these quantities are based. In theory, any radial surface could be used to determine the characteristic area. Some choices are more convenient to work with than others[28]. For example, if a hot fluid were to be inject down tubing, it is preferred to let A_j be the outside surface area of an incremental length of injection tubing, $2\pi r_{to}\Delta L$, and let ΔT_j be the difference between the temperature of the flowing fluid T_1 and the temperature at the cement-formation interface T_2. The $U_j = U_o$, referring to the outside tubing surface area, and Eq. D-1 would be

$$Q = 2\pi r_{to} U_{to} (T_1 - T_2) \Delta L \qquad \text{(D-2)}$$

If the fluid is injected down the casing or casing annulus, the characteristic area would be the inside surface area of the casing, and Eq. D-1 would be written as

$$Q = 2\pi r_{ci} U_{ci} (T_1 - T_2) \Delta L \qquad \text{(D-3)}$$

Subscript ci refers to the inside surface area of the casing.

An expression for the over-all heat transfer coefficient for any well completion can be found by considering the heat transfer mechanisms between the flowing fluid and the cement-formation interface. The reader is referred to the paper by Wilhite[28] or any good heat transfer textbook for a complete discussion and derivation of the over-all heat transfer coefficient.

APPENDIX E

PROGRAM LISTING

```
20    COLOR 13,1,5
30    REM
*********************************************************************
40    REM *
       *
50    REM *                              HEAT.BAS
       *
60    REM *        Heat Transfer/Temperature Gradient Simulation
       *
70    REM *                         Robert D. Pierce
       *
80    REM *
       *
90    REM *                         02 NOVEMBER 1987
       *
100    REM *
        *
110   REM
*********************************************************************
120   CLS
130   KEY OFF : CLEAR
140   LOCATE 6,12 : PRINT CHR$(218);
150   FOR I = 1 TO 50 : PRINT CHR$(196); : NEXT I
160   PRINT CHR$(191)
170   FOR I = 6 TO 17 : LOCATE 1+I,12 : PRINT CHR$(179) : LOCATE 1+I,63
: PRINT CHR$(179) : NEXT I
180   LOCATE 8,18 : PRINT "A PC Simulation of Heat Transfer and"
190   LOCATE 10,22 : PRINT "Temperature Distribution in"
200   LOCATE 12,25 : PRINT "a Circulating Wellbore"
210   LOCATE 14,34 : PRINT "by"
220   LOCATE 16,28 : PRINT "Robert D. Pierce"
230   LOCATE 18,12 : PRINT CHR$(192);
240   FOR I = 1 TO 50 : PRINT CHR$(196); : NEXT I
250   PRINT CHR$(217)
260   PRINT : PRINT : PRINT
270   PRINT TAB(20);"   Press any key to continue"
280   IK$=INKEY$ : IF IK$="" THEN 280 ELSE 290
290   PI = 3.1415927#
300   INJ=75 : REM *** PERIOD OF INJECTION, DAYS ***
310   KC=25 : REM *** THERMAL CONDUCTIVITY OF CASING, BTU/HR*FT*DEG F
***
320   KM=1! : REM *** THERMAL CONDUCTIVITY OF MUD, BTU/HR*FT*DEG F ***
330   TMI=75! : REM *** INITIAL INLET MUD TEMP, DEG F ***
340   NOZ1 = 13 : REM *** NOZZEL DIAMETER, 32D OF INCH ***
350   NOZ2 = 13 : REM *** NOZZEL DIAMETER, 32D OF INCH ***
```

```
360  NOZ3 = 13 : REM *** NOZZEL DIAMETER, 32D OF INCH ***
370  DPOD=6.625 : REM *** DRILL PIPE O.D., INCHES ***
380  DPID=5.965 : REM *** DRILL PIPE I.D., INCHES ***
390  DBIT=8.375 : REM *** DRILL BIT O.D., INCHES ***
400  CSGOD=10.75 : REM *** CASING O.D., INCHES ***
410  CSGWT=51! : REM *** CASING WEIGHT, LB/FT ***
420  CSGID=10! : REM *** CASING I.D., INCHES ***
430  CSGGRD$="N-80" : REM *** CASING GRADE ***
440   Z=15000 : REM *** WELL DEPTH, FEET ***
450   DELZ=500 : REM *** INCREMENTAL DEPTH, FEET ***
460   RHOMUD=10! : REM *** DENSITY OF MUD, LB/GAL ***
470   FR=210 : REM *** FLOW RATE, GAL/MIN ***
480   MU=110! : REM *** VISCOSITY, LB/FT.HR (CP = MU*0.4134) ***
490   THETA=70 : REM *** DIAL READING ON ROTATIONAL VISCOMETER ***
500   CPM=.4 : REM *** MUD SPECIFIC HEAT, BTU/LB*DEG F ***
510   CPF=.2 : REM *** FORMATION SPECIFIC HEAT, BTU/LB.DEG F ***
520   TSA=70 : REM *** SURFACE AIR TEMPERATURE, DEG F ***
530   UP = 30 : REM *** HEAT TRANS. COEFF. (PIPE), BTU/HR*SQ.FT*DEG F
***
540   UA = 1! : REM *** HEAT TRANS. COEFF. (ANNULUS), BTU/HR*SQ.FT*DEG
F ***
550   GRAD=.0127 : REM *** ASSUMED TEMPERATURE GRADIENT, DEG F/FT ***
560   TSE = 59.5 : REM *** SURFACE EARTH TEMPERATURE, DEG F ***
570   SCREEN 0 : WIDTH 80
580   COLOR 14,1,1
590   CLS
600  GOSUB 920
610   M$=STRING$(77,"x") : N$=STRING$(21,"x") : R$=STRING$(26,"x")
620   PRINT M$
630   PRINT N$;TAB(57);N$
640   PRINT N$;TAB(29);"Program Master Menu";TAB(57);N$
650   PRINT N$;TAB(57);N$
660   PRINT N$;TAB(33);"Select One";TAB(57);N$
670   PRINT N$;TAB(57);N$
680   PRINT R$;" "; DATE$ ; " xxx " ; TIME$ ;" ";R$
690   PRINT
700   COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
710   PRINT TAB(12);"  (B)........ To Change/View Program Parameters"
720   PRINT
730   PRINT TAB(12);"  (C).........To Execute Graphics Routine"
740   PRINT
750   PRINT TAB(12);"  (D).........To Print Out Table"
760   PRINT
770   PRINT TAB(12);"  (E).........To Run Simulation"
780   PRINT
790   PRINT TAB(12);"  (F).........To Determine Pressure Losses"
800   PRINT
810   PRINT TAB(12); "To continue, press a key."
820   BEEP : BEEP
830  IK$=INKEY$ : IF IK$="" THEN GOTO 830 ELSE GOTO 840
```

```
840  IF IK$="A" OR IK$="a" THEN END
850  IF IK$="B" OR IK$="b" THEN GOTO 3290
860  IF IK$="C" OR IK$="c" THEN GOTO 6180
870  IF IK$="D" OR IK$="d" THEN GOSUB 1780
880  IF IK$="E" OR IK$="e" THEN GOTO 2500
890  IF IK$="F" OR IK$="f" THEN GOTO 4830
900  GOTO 570
910  REM
920  REM ************ CALCULATIONS SUBROUTINE
**************************
930  REM
940  AREABIT = (PI/4096)*((NOZ1)^2 + (NOZ2)^2 + (NOZ3)^2)
950  PRESBIT = ((8.311E-05)*(RHOMUD)*(FR)^2)/((.95*.95)*(AREABIT)^2)
960  IF Z < 3000 THEN KF = .6 : REM *** FORMATION CONDUCTIVITY,
BTU/HR*FT*DEG F ***
970  IF Z >= 3000 AND Z <= 13000 THEN KF = 1.5 + 3!*(Z/13000)^3
980  IF Z > 13000 THEN KF = 4.5
990  IF Z <10000 THEN RHOFOR = 122 + .0046*Z : REM *** DENSITY OF
FORMATION, LB/CU.FT ***
1000  IF Z >= 10000 THEN RHOFOR = 165
1010  B = ((DBIT/2)*UA)/((DPOD/2)*UP)
1020  A = ((FR*RHOMUD*60)*CPM)/(2*PI*(DPOD/24)*UP)
1030  C1 = (B/(2*A))*(1+SQR(1+4/B))
1040  C2 = (B/(2*A))*(1-SQR(1+4/B))
1050  C3 = 1+((B/2)*(1+(1+4/B)^.5))
1060  C4 = 1+((B/2)*(1-(1+4/B)^.5))
1070  K2 =
(GRAD*A-(TMI-TSE+GRAD*A)*EXP(C1*Z)*(1-C3))/(EXP(C2*Z)*(1-C4)-EXP(C1*Z-
)*(1-C3))
1080  K1 = TMI-K2-TSE+GRAD*A
1090  OPEN "O",1,"HEAT1.DTA"
1100  FOR L = 0 TO Z STEP DELZ
1110      TP = K1*EXP(C1*L)+K2*EXP(C2*L)+GRAD*L+TSE-GRAD*A
1120      TA = K1*C3*EXP(C1*L)+K2*C4*EXP(C2*L)+GRAD*L+TSE
1130      WRITE #1,L,TP,TA
1140      NEXT L
1150  CLOSE 1
1160  REM
1170  REM *** BEGIN RAMEY'S CALCULATIONS ***
1180  REM
1190  HP=4.36
1200  OPEN "O",2,"RAMEY.DTA"
1210  FOR L = 0 TO Z STEP DELZ
1220      UR = 1/(1/HP+(DPOD-DPID)/(24*KC))
1230      FX = (.04*INJ*24)/((DPOD/2)/12)^2
1240      FY = .4342945*LOG(FX)
1250      FT = .0018302*FY^3 - .045016*FY^2 + .49045*FY - .44056
1260      REM *** FT IS RAMEY'S TRANSIENT HEAT-CONDUCTION TIME
FUNCTION ***
1270      W = 1440*FR*RHOMUD
```

```
1280      R1 = DPID/2
1290      REM *** KF = THERMAL CONDUCTIVITY OF THE EARTH,
BTU/DAY*FT*DEG F
1300      FIRST = W/(2*PI*R1)
1310      SECOND = (CPM*12)/(24*KF*UR)
1320      THIRD = (KF*24)+(R1/2)*UR*FT
1330      A = FIRST*SECOND*THIRD
1340      T = (GRAD*L)+TSA-(GRAD*A)+(TMI+(GRAD*A)-TSA)*EXP(-L/A)
1350      WRITE #2,L,T
1360      NEXT L
1370  CLOSE 2
1380  RETURN
1390  REM
1400  REM
1410  REM *** NEWTONIAN FLUID MODEL ***
1420  F$ = "Newtonian"
1430  VBARDP = FR/(2.448*(DPID)^2)
1440  VBARAN = FR/(2.448*((CSGID^2)-(DPID^2)))
1450  NREDP = 928*RHOMUD*VBARDP*(DPID)/(MU*.4134)
1460  NREAN = 757*RHOMUD*VBARAN*(CSGOD-DPID)/(MU*.4134)
1470  PR = CPM*(.4134*MU)/KM
1480  IF NREDP < 2100 THEN FLOCON$ = "LAMINAR"
1490  IF NREAN < 2100 THEN CONFLO$ = "LAMINAR"
1500  IF NREDP >= 2100 THEN FLOCON$ = "TURBULENT"
1510  IF NREAN >= 2100 THEN CONFLO$ = "TURBULENT"
1520  IF NREDP < 2100 THEN 1550 ELSE 1640
1530  IF NREAN < 2100 THEN 1550 ELSE 1640
1540  REM
1550  REM -------- LAMINAR FLOW CALCULATIONS
--------------------------------
1560  FRIC = 64/NREDP
1570  NUBAR = 4.36
1580  HP = (NUBAR*KM)/DPID
1590  DPRESP = ((MU*.4134)*VBARDP*Z)/(1500*(DPID^2))
1600  DPRESA = ((MU*.4134)*VBARAN*Z)/(1000*((CSGID-DPOD)^2))
1610  DPTOT = DPRESP + DPRESA + PRESBIT
1620  GOSUB 920
1630  GOTO 5120
1640  REM -------- TURBULENT FLOW CALCULATIONS
------------------------------
1650  REM
1660  IF NREDP < 20000 THEN FRIC = .316*NREDP^(-.25) ELSE GOTO 1670
1670  FRIC = .184*NREDP^(-.2)
1680  NUBAR = .023*(NREDP^.8)*PR^(1/3)
1690  HP = (NUBAR*KM)/DPID
1700  DPRESP =
((RHOMUD^.75)*(VBARDP^1.75)*((MU*.4134)^.25)*Z)/(1800*(DPID^1.25))
1710  DPRESA =
((RHOMUD^.75)*(VBARAN^1.75)*((MU*.4134)^.25)*Z)/(1396*(DPID^1.25))
1720  DPTOT = DPRESP + DPRESA + PRESBIT
```

```
1730  GOSUB 920
1740  GOTO 5120
1750  REM
1760  REM *********** END CALCULATIONS
****************************************
1770  REM
1780  REM *********** ROUTINE TO PRINT FILE CONTENTS
*************************
1790  REM
1800  CLS
1810  INPUT "Do you want the Holmes & Swift model (Y/N)";Y$
1820  IF LEFT$(Y$,1)-"Y" OR LEFT$(Y$,1)-"y" THEN 1830 ELSE 2180
1830  PRINT : PRINT
1840  PRINT : INPUT "DO YOU WANT A HARD COPY (Y/N)";Y$
1850  IF LEFT$(Y$,1)-"Y" OR LEFT$(Y$,1)-"y" THEN 2030
1860  PRINT : PRINT
1870  A$ - "###.##" : B$ - "######.##"
1880  PRINT TAB(3);"DEPTH";TAB(23);"DRILL PIPE TEMPERATURE"; TAB(50);
"ANNULUS TEMPERATURE"
1890  PRINT TAB(3);"-----";TAB(23);"----------------------"; TAB(50);
"-------------------"
1900  OPEN "I",1,"HEAT1.DTA"
1910  IF EOF(1) THEN CLOSE 1 : GOTO 1990
1920  INPUT #1,L,TP,TA
1930  PRINT USING "##### FEET";L;
1940  PRINT TAB(26);" ";
1950  PRINT USING "###.## DEG F";TP;
1960  PRINT TAB(51);"  ";
1970  PRINT USING "###.## DEG F";TA
1980  GOTO 1910
1990  PRINT : PRINT "HIT ANY KEY TO RETURN TO MAIN MENU"
2000  IK$ - INKEY$ : IF IK$ - "" THEN GOTO 2000 ELSE GOTO 2010
2010  IK$ - INKEY$ : IF IK$ - "INKEY$" THEN GOTO 570
2020  RETURN
2030  REM
2040  REM *********** ROUTINE TO PRINT A HARD COPY OF TABLE
*****************
2050  REM
2060  LPRINT : LPRINT
2070  LPRINT TAB(3);"DEPTH";TAB(23);"DRILL PIPE TEMPERATURE"; TAB(50);
"ANNULUS TEMPERATURE"
2080  LPRINT TAB(3);"-----";TAB(23);"----------------------"; TAB(50);
"-------------------"
2090  OPEN "I",1,"HEAT1.DTA"
2100  IF EOF(1) THEN CLOSE 1 : RETURN
2110  INPUT #1,L,TP,TA
2120  LPRINT USING "##### FEET";L;
2130  LPRINT TAB(26);" ";
2140  LPRINT USING "###.## DEG F";TP;
2150  LPRINT TAB(51);" ";
```

```
2160  IF LEFT$(Y$,1)="Y" OR LEFT$(Y$,1)="y" THEN 2540 ELSE 570
2170  GOTO 2100
2180  REM *** ROUTINE TO PRINT RAMEY'S DATA ***
2190  CLS
2200  PRINT : PRINT
2210  PRINT : INPUT "DO YOU WANT A HARD COPY (Y/N)";Y$
2220  IF LEFT$(Y$,1)="Y" OR LEFT$(Y$,1)="y" THEN 2370
2230  PRINT : PRINT
2240  PRINT TAB(3);"DEPTH";TAB(23);"WELLBORE FLUID TEMPERATURE"
2250  PRINT TAB(3);"-----";TAB(23);"--------------------------"
2260  OPEN "I",1,"RAMEY.DTA"
2270  IF EOF(1) THEN CLOSE 1 : GOTO 2330
2280  INPUT #1,L,T
2290  PRINT USING "##### FEET";L;
2300  PRINT TAB(26);" ";
2310  PRINT USING "###.## DEG F";T
2320  GOTO 2270
2330  PRINT : PRINT "HIT ANY KEY TO RETURN TO MAIN MENU"
2340  IK$ = INKEY$ : IF IK$ = "" THEN GOTO 2340 ELSE GOTO 2350
2350  IK$ = INKEY$ : IF IK$ = "INKEY$" THEN GOTO 570
2360  RETURN
2370  REM
2380  REM *********** ROUTINE TO PRINT A HARD COPY OF TABLE
*****************
2390  REM
2400  LPRINT : LPRINT
2410  LPRINT TAB(3);"DEPTH";TAB(23);"WELLBORE FLUID TEMPERATURE"
2420  LPRINT TAB(3);"-----";TAB(23);"--------------------------"
2430  OPEN "I",1,"RAMEY.DTA"
2440  IF EOF(1) THEN CLOSE 1 : RETURN
2450  INPUT #1,L,T
2460  LPRINT USING "##### FEET";L;
2470  LPRINT TAB(26);" ";
2480  LPRINT USING "###.## DEG F";T
2490  GOTO 2440
2500 REM ************** SIMULATION ********************************
2510 CLS
2520 INPUT "Have you run the fluid model yet (Y/N)";Y$
2530  IF LEFT$(Y$,1)="Y" OR LEFT$(Y$,1)="y" THEN 2540 ELSE 4830
2540 SCREEN 1,0 : COLOR 14,0
2550 GOSUB 2620 : REM --- DRAW BORDER ---
2560 LOCATE 4,2 :  PRINT "Press any key to continue."
2570 GOSUB 3150 : REM --- DRAW WELLBORE ---
2580 IK$ = INKEY$ : IF IK$ = "" THEN GOTO 2580 ELSE 2590
2590 GOSUB 2650 : REM --- UPDATE SCREEN ---
2600 GOSUB 2870 : REM --- SIMULATION EXECUTION ---
2610 GOTO 570
2620 REM --- DRAW BORDER ---
2630 LINE (1,1) - (318,198),2,B
2640 RETURN
```

```
2650 REM --- PRINT DATA ON SCREEN ---
2660 LOCATE 7,2 : PRINT "FLOW RATE =";FR;" GPM"
2670 LOCATE 8,2 : PRINT "VBARDP =";: PRINT USING "####.## ";VBARDP;:
PRINT " FPS"
2680 IF FLOCON$ = "TURBULENT" THEN R$ = "TURB" ELSE R$="LAM"
2690 LOCATE 10,2 : PRINT "VBARAN =";: PRINT USING "####.## ";VBARAN;:
PRINT " FPS"
2700 IF CONFLO$ = "TURBULENT" THEN Q$ = "TURB" ELSE Q$="LAM"
2710 LOCATE 9,2 : PRINT "NREDP =";: PRINT USING "###,###,###
";NREDP;:PRINT R$
2720 LOCATE 11,2 : PRINT "NREAN =";: PRINT USING "###,###,###
";NREAN;:PRINT Q$
2730 LOCATE 12,2 : PRINT "DRILL PIPE TEMP = ";:PRINT USING "###.#
";TP;:PRINT "DEG F"
2740 LOCATE 13,2 : PRINT "ANNULUS TEMP = ";:PRINT USING "###.#
";TA;:PRINT "DEG F"
2750 LOCATE 17,2 : PRINT "PRESS:"
2760 LOCATE 19,3 : PRINT "(S) CONTINUE SIMULATION"
2770 LOCATE 20,3 : PRINT "(A)"
2780 LOCATE 21,3 : PRINT "(B)"
2790 LOCATE 22,3 : PRINT "(M) RETURN TO MAIN MENU"
2800 IK$=INKEY$ : IF IK$="" THEN GOTO 2800 ELSE GOTO 2810
2810 IF IK$="S" OR IK$="s" THEN GOTO 2860
2820 IF IK$="A" OR IK$="a" THEN GOTO 2860
2830 IF IK$="B" OR IK$="b" THEN GOTO 2860
2840 IF IK$="C" OR IK$="c" THEN GOTO 2860
2850 IF IK$="M" OR IK$="m" THEN GOTO 570
2860 RETURN
2870 REM --- SIMULATION EXECUTION ---
2880 X = 232
2890 FOR Y = 20 TO 180
2900 LINE (X-7,Y) - (X+7,Y+10),2,BF
2910 LINE (X-7,Y-10) - (X+7,Y),0,BF
2920 FOR N = 1 TO 100
2930 NEXT N
2940 NEXT Y
2950 X1 = 220 : X2 = 244
2960 FOR Y = 189 TO 100 STEP -1
2970     LINE (X1-3,Y) - (X1+3,Y-10),2,BF
2980     LINE (X1-3,Y+10) - (X1+3,Y),0,BF
2990     LINE (X2-3,Y) - (X2+3,Y-10),2,BF
3000     LINE (X2-3,Y+10) - (X2+3,Y),0,BF
3010     FOR N = 1 TO 100
3020         NEXT N
3030 NEXT Y
3040 X1=215 : X2=249
3050 FOR Y = 100 TO 19 STEP -1
3060     LINE (X1-6,Y) - (X1+6,Y-10),2,BF
3070     LINE (X1-6,Y+10) - (X1+6,Y),0,BF
3080     LINE (X2-6,Y) - (X2+6,Y-10),2,BF
```

```
3090     LINE (X2-6,Y+10) - (X2+6,Y),0,BF
3100     FOR N = 1 TO 100
3110         NEXT N
3120 NEXT Y
3130 IK$=INKEY$ : IF IK$="" THEN GOTO 3130 ELSE GOTO 3140
3140 RETURN
3150 REM --- DRAW WELLBORE ---
3160 LINE (208,10) - (208,100),2
3170 LINE - (216,100),2
3180 LINE - (216,190),2
3190 LINE - (248,190),2
3200 LINE - (248,100),2
3210 LINE - (256,100),2
3220 LINE - (256,10),2
3230 LINE (224,10) - (224,180),1
3240 LINE (240,10) - (240,180),1
3250 LINE (208,10) - (224,10),2
3260 LINE (240,10) - (256,10),2
3270 LINE (200,0) - (200,199)
3280 RETURN
3290 REM *** PARAMETER CHANGE MENU ***
3300 CLS
3310  PRINT M$
3320  PRINT N$;TAB(57);N$
3330  PRINT N$;TAB(26);"Parameter Change/View Menus";TAB(57);N$
3340  PRINT N$;TAB(57);N$
3350  PRINT N$;TAB(33);"Select One";TAB(57);N$
3360  PRINT N$;TAB(57);N$
3370  PRINT R$;" "; DATE$ ; " xxx " ; TIME$ ;" ";R$
3380  PRINT
3390  COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
3400  PRINT TAB(12);"    (B)........To Change Drilling Fluid
Parameters"
3410  PRINT
3420  PRINT TAB(12);"    (C)........To Change Drill Pipe Parameters"
3430  PRINT
3440  PRINT TAB(12);"    (D)........To Change Wellbore/Formation
Parameters"
3450  PRINT
3460  PRINT TAB(12);"    (E)........To Change Casing Parameters"
3470  PRINT
3480  PRINT TAB(12);"    (M)........To Return To Main Menu"
3490  PRINT : PRINT TAB(12); "To continue, press a key." : BEEP
3500  IK$=INKEY$ : IF IK$="" THEN GOTO 3500 ELSE GOTO 3510
3510  IF IK$="A" OR IK$="a" THEN END
3520  IF IK$="B" OR IK$="b" THEN GOTO 3570
3530  IF IK$="C" OR IK$="c" THEN GOTO 3910
3540  IF IK$="D" OR IK$="d" THEN GOTO 4200
3550  IF IK$="E" OR IK$="e" THEN GOTO 4510
3560  IF IK$="M" OR IK$="m" THEN GOTO 570
```

```
3570  REM *** DRILLING FLUID PARAMETERS ***
3580  CLS
3590  PRINT M$
3600  PRINT N$;TAB(57);N$
3610  PRINT N$;TAB(27);"Drilling Fluid Parameters";TAB(57);N$
3620  PRINT N$;TAB(57);N$
3630  PRINT N$;TAB(33);"Select One";TAB(57);N$
3640  PRINT N$;TAB(57);N$
3650  PRINT R$;" " ; DATE$ ; " xxx " ; TIME$ ; " ";R$
3660  PRINT
3670  COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
3680  PRINT TAB(12);"  (B) Thermal Conductivity of Mud -
";KM;"Btu/(hr*ft*deg F)"
3690  PRINT
3700  PRINT TAB(12);"  (C) Initial Inlet Mud Temperature - ";TMI;"deg
F"
3710  PRINT
3720  PRINT TAB(12);"  (D) Density of Mud - ";RHOMUD;" Lb/gal"
3730  PRINT
3740  PRINT TAB(12);"  (E) Flow Rate - ";FR;" Gal/min"
3750  PRINT
3760  PRINT TAB(12);"  (F) Absolute Viscosity of Mud - ";MU;"
Lb/(ft*hr)";" ("MU*.4134" CP )"
3770  PRINT
3780  PRINT TAB(12);"  (G) Specific heat of Mud - ";CPM;" Btu/(lb*deg
F)"
3790  PRINT
3800  PRINT TAB(12);"  (M) Return to Parameters Menu"
3810  PRINT : PRINT TAB(12); "To continue, press a key." : BEEP
3820  IK$-INKEY$ : IF IK$-"" THEN GOTO 3820 ELSE GOTO 3830
3830  IF IK$-"A" OR IK$-"a" THEN END
3840  IF IK$-"B" OR IK$-"b" THEN INPUT "New value for thermal
conductivity of mud -";KM : GOTO 3570
3850  IF IK$-"C" OR IK$-"c" THEN INPUT "New value for initial inlet
mud temperature -";TMI : GOTO 3570
3860  IF IK$-"D" OR IK$-"d" THEN INPUT "New value for mud density =
";RHOMUD : GOTO 3570
3870  IF IK$-"E" OR IK$-"e" THEN INPUT "New value for flow rate - ";FR
: GOTO 3570
3880  IF IK$-"F" OR IK$-"f" THEN INPUT "New value for viscosity - ";MU
: GOTO 3570
3890  IF IK$-"G" OR IK$-"g" THEN INPUT "New value for specific heat of
mud - ";CPM : GOTO 3570
3900  IF IK$-"M" OR IK$-"m" THEN GOTO 3290
3910  REM *** DRILL PIPE PARAMETERS ***
3920  CLS
3930  PRINT M$
3940  PRINT N$;TAB(57);N$
3950  PRINT N$;TAB(29);"Drill Pipe Parameters";TAB(57);N$
3960  PRINT N$;TAB(57);N$
```

```
3970  PRINT N$;TAB(33);"Select One";TAB(57);N$
3980  PRINT N$;TAB(57);N$
3990  PRINT R$;" " ; DATE$ ; " xxx " ; TIME$ ; " ";R$
4000  PRINT
4010  COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
4020  PRINT TAB(12);"  (B) Heat Trans. Coeff. at Pipe Wall -
";UP;"Btu/(hr*ft^2*deg F)"
4030  PRINT
4040  PRINT TAB(12);"  (C) Drill Pipe Inner Diameter - ";DPID;"inches"

4050  PRINT
4060  PRINT TAB(12);"  (D) Drill Pipe Outer Diameter - ";DPOD;"inches"

4070  PRINT
4080  PRINT TAB(12);"  (E) Incremental Length - ";DELZ;" ft"
4090  PRINT
4100  PRINT TAB(12);"  (M) Return to Parameter Menu"
4110  PRINT : PRINT TAB(12); "To continue, press a key." : BEEP
4120  PRINT : PRINT
4130  IK$=INKEY$ : IF IK$="" THEN GOTO 4130 ELSE GOTO 4140
4140  IF IK$="A" OR IK$="a" THEN END
4150  IF IK$="B" OR IK$="b" THEN INPUT "New value for heat transfer
coefficient - ";UP : GOTO 3910
4160  IF IK$="C" OR IK$="c" THEN INPUT "New value for drill pipe inner
diameter -";DPID : GOTO 3910
4170  IF IK$="D" OR IK$="d" THEN INPUT "New value for drill pipe outer
diameter =";DPOD : GOTO 3910
4180  IF IK$="E" OR IK$="e" THEN INPUT "New value for delz - ";DELZ :
GOTO 3910
4190  IF IK$="M" OR IK$="m" THEN GOTO 3290
4200  REM *** WELLBORE/FORMATION PARAMETERS ***
4210  CLS
4220  PRINT M$
4230  PRINT N$;TAB(57);N$
4240  PRINT N$;TAB(29);"Wellbore/Formation";TAB(57);N$
4250  PRINT N$;TAB(33);"Parameters";TAB(57);N$
4260  PRINT N$;TAB(33);"Select One";TAB(57);N$
4270  PRINT N$;TAB(57);N$
4280  PRINT R$;" " ; DATE$ ; " xxx " ; TIME$ ; " ";R$
4290  PRINT
4300  COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
4310  PRINT TAB(12);"  (B) Depth of Well - ";Z;"feet"
4320  PRINT TAB(12);"  (C) Period of Injection - ";INJ;" days"
4330  PRINT TAB(12);"  (D) Temperature Gradient - ";GRAD;" deg F/ft"
4340  PRINT TAB(12);"  (E) Surface Air Temperature - ";TSA;" deg F"
4350  PRINT TAB(12);"  (F) Wellbore Diameter - ";DBIT;" inches"
4360  PRINT TAB(12);"  (G) Heat transfer coefficient (annulus) -";UA;"
Btu/(hr*sq ft*deg F)"
4370  PRINT TAB(12);"  (H) Formation Density - ";RHOFOR;" lb/cu ft"
```

```
4380  PRINT TAB(12);"  (I) Formation Conductivity = ";KF;"
Btu/(hr*ft*deg F)"
4390  PRINT TAB(12);"  (M) Return to Parameter Menu"
4400  PRINT : PRINT TAB(12); "To continue, press a key." : BEEP
4410  PRINT : PRINT
4420  IK$=INKEY$ : IF IK$="" THEN GOTO 4420 ELSE GOTO 4430
4430  IF IK$="A" OR IK$="a" THEN END
4440  IF IK$="B" OR IK$="b" THEN INPUT "New value for well depth =";Z
: GOTO 4200
4450  IF IK$="C" OR IK$="c" THEN INPUT "New value for period of
injection = ";INJ : GOTO 4200
4460  IF IK$="D" OR IK$="d" THEN INPUT "New value for temp grad =
";GRAD : GOTO 4200
4470  IF IK$="E" OR IK$="e" THEN INPUT "New value for surface air temp
= ";TSA : GOTO 4200
4480  IF IK$="F" OR IK$="f" THEN INPUT "New value for wellbore
diameter = ";DBIT : GOTO 4200
4490  IF IK$="G" OR IK$="g" THEN INPUT "New value for heat transfer
coeff. (annulus = ";UA : GOTO 4200
4500  IF IK$="M" OR IK$="m" THEN GOTO 3290
4510  REM *** CASING PROGRAM PARAMETERS ***
4520  CLS
4530  PRINT M$
4540  PRINT N$;TAB(57);N$
4550  PRINT N$;TAB(27);"Casing Program Parameters";TAB(57);N$
4560  PRINT N$;TAB(57);N$
4570  PRINT N$;TAB(33);"Select One";TAB(57);N$
4580  PRINT N$;TAB(57);N$
4590  PRINT R$;" " ; DATE$ ; " xxx " ; TIME$ ; " ";R$
4600  PRINT
4610  COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
4620  PRINT TAB(12);"  (B) Thermal Conductivity of Casing =
";KC;"Btu/(hr*ft*deg F)"
4630  PRINT
4640  PRINT TAB(12);"  (C) Inside Diameter of Casing = ";CSGID;"
Inches"
4650  PRINT
4660  PRINT TAB(12);"  (D) Outside Diameter of Casing = ";CSGOD;"
Inches"
4670  PRINT
4680  PRINT TAB(12);"  (E) Weight of Casing = ";CSGWT;" Lb/ft"
4690  PRINT
4700  PRINT TAB(12);"  (F) Grade of Casing = ";CSGGRD$
4710  PRINT
4720  PRINT TAB(12);"  (M) Return to Parameter Menu"
4730  PRINT : PRINT TAB(12); "To continue, press a key." : BEEP
4740  PRINT : PRINT
4750  IK$=INKEY$ : IF IK$="" THEN GOTO 4750 ELSE GOTO 4760
4760  IF IK$="A" OR IK$="a" THEN END
```

```
4770  IF IK$="B" OR IK$="b" THEN INPUT "New value for thermal
conductivity of casing =";KC : GOTO 4510
4780  IF IK$="C" OR IK$="c" THEN INPUT "New value for casing I.D. =
";CSGID : GOTO 4510
4790  IF IK$="D" OR IK$="d" THEN INPUT "New value for casing O.D. =
";CSGOD : GOTO 4510
4800  IF IK$="E" OR IK$="e" THEN INPUT "New value for casing weight =
";CSGWT : GOTO 4510
4810  IF IK$="F" OR IK$="f" THEN INPUT "New value for casing grade =
";CSGGRD$ : GOTO 4510
4820  IF IK$="M" OR IK$="m" THEN GOTO 3290
4830  REM *** MUD RHEOLOGY MODEL ***
4840  CLS
4850  PRINT M$
4860  PRINT N$;TAB(57);N$
4870  PRINT N$;TAB(27);"Fluid Rheology Model";TAB(57);N$
4880  PRINT N$;TAB(57);N$
4890  PRINT N$;TAB(33);"Select One";TAB(57);N$
4900  PRINT N$;TAB(57);N$
4910  PRINT R$;" " ; DATE$ ; " xxx " ; TIME$ ; " ";R$
4920  PRINT
4930  COLOR 4,15 : PRINT "(A) QUIT "; : COLOR 14,1
4940  PRINT TAB(20);"  (B) Newtonian"
4950  PRINT
4960  PRINT TAB(20);"  (C) Bingham Plastic"
4970  PRINT
4980  PRINT TAB(20);"  (D) Power - Law"
4990  PRINT
5000  PRINT TAB(20);"  (E) Return to simulation"
5010  PRINT
5020  PRINT TAB(20);"  (M) Return to Main Menu"
5030  PRINT : PRINT TAB(12); "To continue, press any key." : BEEP
5040  PRINT : PRINT
5050  IK$=INKEY$ : IF IK$="" THEN GOTO 5050 ELSE GOTO 5060
5060  IF IK$="A" OR IK$="a" THEN END
5070  IF IK$="B" OR IK$="b" THEN GOTO 1410
5080  IF IK$="C" OR IK$="c" THEN GOTO 5560
5090  IF IK$="D" OR IK$="d" THEN GOTO 5790
5100  IF IK$="E" OR IK$="e" THEN GOTO 2500
5110  IF IK$="M" OR IK$="m" THEN GOTO 570
5120  CLS
5130  PRINT M$
5140  PRINT N$;TAB(57);N$
5150  PRINT N$;TAB(28);"Fluid Flow Conditions";TAB(57);N$
5160  PRINT N$;TAB(57);N$
5170  PRINT R$;" "; DATE$ ; " xxx " ; TIME$ ;" ";R$
5180  PRINT
5190  COLOR 4,15 : PRINT "Fluid model chosen is ";F$ : COLOR 14,1
5200  PRINT
```

```
5210  PRINT TAB(10);:COLOR 14,0:PRINT"Average velocity in drill pipe =
";: PRINT USING "####.## ";VBARDP;: PRINT " ft/sec"
5220  COLOR 14,1,1
5230  PRINT TAB(10);:COLOR 14,0:PRINT"Average velocity in the annulus
= ";: PRINT USING "####.## ";VBARAN;: PRINT " ft/sec"
5240  COLOR 14,1,1
5250  PRINT TAB(10);:COLOR 14,0:PRINT"Reynold's Number in drill pipe =
";: PRINT USING "###,###,### ";NREDP;: PRINT FLOCON$
5260  COLOR 14,1,1
5270  PRINT TAB(10);:COLOR 14,0:PRINT"Reynold's Number in annulus =
";: PRINT USING "###,###,### ";NREAN;: PRINT CONFLO$
5280  COLOR 14,1,1
5290  PRINT TAB(10);:COLOR 14,0:PRINT"Darcy friction factor = ";:
PRINT USING "#.##### ";FRIC
5300  COLOR 14,1,1
5310  PRINT TAB(10);:COLOR 14,0:PRINT"Prandtl Number = ";: PRINT USING
"##.### ";PR
5320  COLOR 14,1,1
5330  PRINT TAB(10);:COLOR 14,0:PRINT"Nusselt Number = ";: PRINT USING
"##,###.## ";NUBAR
5340  COLOR 14,1,1
5350  PRINT TAB(10);:COLOR 14,0:PRINT "Pressure loss in drill pipe =
";: PRINT USING "##,###.# ";DPRESP;:PRINT " psi"
5360  COLOR 14,1,1
5370  PRINT TAB(10);:COLOR 14,0:PRINT "Pressure loss in annulus =
";:PRINT USING "#,###.# ";DPRESA;:PRINT " psi"
5380  COLOR 14,1,1
5390  PRINT TAB(10);:COLOR 14,0:PRINT "Pressure loss in bit = ";:PRINT
USING "#,###.# ";PRESBIT;:PRINT " psi"
5400  COLOR 14,1,1
5410  PRINT TAB(10);:COLOR 14,0:PRINT "Total Pressure loss in system =
";:PRINT USING "##,###.#";DPTOT;:PRINT " psi"
5420  COLOR 14,1,1
5430  IF IK$="C" OR IK$="c" THEN PRINT TAB(10);:COLOR 14,0:PRINT
"Critical Reynold's number (drill pipe) = ";NRECDP  ELSE 5460
5440  COLOR 14,1,1
5450  PRINT TAB(10);:COLOR 14,0:PRINT "Critical Reynold's number
(annulus) = ";NRECAN : COLOR 14,1,1
5460  IF IK$="D" OR IK$="d" THEN GOTO 5470 ELSE 5510
5470  PRINT TAB(10);:COLOR 14,0:PRINT "Flow behavior index (n) =
";NLAW
5480  COLOR 14,1,1
5490  PRINT TAB(10);:COLOR 14,0:PRINT "Consistency index (K) = ";KLAW
5500  COLOR 14,1,1
5510  PRINT : PRINT "Hit any key to return to Fluid Rheology menu."
5520  BEEP
5530  IK$=INKEY$ : IF IK$ = "" THEN GOTO 5530 ELSE GOTO 5540
5540  GOTO 4830
5550  REM
5560  REM *** BINGHAM PLASTIC MODEL ***
```

```
5570  REM
5580  F$ - "Bingham Plastic"
5590  VBARDP - FR/(2.448*(DPID)^2)
5600  VBARAN - FR/(2.448*((CSGID^2)-(DPID^2)))
5610  MUP - THETA - (MU*.4134)
5620  YP - (MU*.4134) - MUP
5630  NHEDP - (37100!*RHOMUD*YP*(DPID^2))/(MUP^2)
5640  NHEAN - (24700*RHOMUD*YP*((CSGID-DPOD)^2))/(MUP^2)
5650  NREDP - (928*RHOMUD*VBARDP*DPID)/MUP
5660  NREAN - (757*RHOMUD*VBARAN*(CSGID-DPOD))/MUP
5670  HED1 - LOG(NHEDP)
5680  HED2 - LOG(NHEAN)
5690  NRECDP - EXP(-.0019841*(HED1^3) + .080586*(HED1^2) -
(.71107*HED1) + 9.4408)
5700  NRECAN - EXP(-.0019841*(HED2^3) + .080586*(HED2^2) -
(.71107*HED2) + 9.4408)
5710  PR - CPM*(.4134*MU)/KM
5720  IF NREDP < NRECDP THEN FLOCON$ - "LAMINAR"
5730  IF NREAN < NRECAN THEN CONFLO$ - "LAMINAR"
5740  IF NREDP >- NRECDP THEN FLOCON$ - "TURBULENT"
5750  IF NREAN >- NRECDP THEN CONFLO$ - "TURBULENT"
5760  IF NREDP < NRECDP THEN 1550 ELSE 1640
5770  IF NREAN < NRECAN THEN 1550 ELSE 1640
5780  REM
5790  REM *** POWER - LAW MODEL ***
5800  REM
5810  F$ - "Power Law"
5820  VBARDP - FR/(2.448*(DPID)^2)
5830  VBARAN - FR/(2.448*((CSGID^2)-(DPID^2)))
5840  NLAW - 3.32*.4342945*LOG(THETA/(MU*.4134))
5850  KLAW - (510*(MU*.4134))/(511^NLAW)
5860  NREDP -
((89100!*RHOMUD*(VBARDP^(2-NLAW))/KLAW))*(((.0416*DPID)/(3+(1/NLAW)))-
^NLAW)
5870  NREAN
-((109000!*RHOMUD*VBARAN^(2-NLAW)/KLAW)*(((.0208*(CSGID-DPOD))/(2+(1/-
NLAW)))^NLAW))
5880  PR - CPM*(.4134*MU)/KM
5890  IF NREDP < 2100 THEN FLOCON$ - "LAMINAR"
5900  IF NREAN < 2100 THEN CONFLO$ - "LAMINAR"
5910  IF NREDP >- 2100 THEN FLOCON$ - "TURBULENT"
5920  IF NREAN >- 2100 THEN CONFLO$ - "TURBULENT"
5930  IF NREDP < 2100 THEN 5950 ELSE 6050
5940  IF NREAN < 2100 THEN 5950 ELSE 6050
5950  REM
5960  REM -------- LAMINAR FLOW CALCULATIONS
-------------------------------
5970  FRIC - 64/NREDP
5980  NUBAR - 4.36
5990  HP - (NUBAR*KM)/DPID
```

```
6000  DPRESP =
((KLAW*(VBARDP^NLAW)*Z*((3+1/NLAW)/.0208)^NLAW)/(144000!*DPID^(1+NLAW-
)))
6010  DPRESA =
((KLAW*(VBARAN^NLAW)*Z*((2+1/NLAW)/.0208)^NLAW)/(144000!*(CSGID-DPOD)-
^(1+NLAW)))
6020  DPTOT = DPRESP + DPRESA + PRESBIT
6030  GOSUB 920
6040  GOTO 5120
6050  REM -------- TURBULENT FLOW CALCULATIONS
--------------------------------
6060  REM
6070  IF NREDP < 20000 THEN FRIC = .316*NREDP^(-.25) ELSE GOTO 6100
6080  IF NREAN < 20000 THEN FRIC = .316*NREAN^(-.25) ELSE GOTO 6100
6090  FRIC = .184*NREDP^(-.2)
6100  FRIC = .184*NREAN^(-.2)
6110  NUBAR = .023*(NREDP^.8)*PR^(1/3)
6120  HP = (NUBAR*KM)/DPID
6130  DPRESP = (FRIC*RHOMUD*Z*VBARDP^2)/(25.8*DPID)
6140  DPRESA = (FRIC*RHOMUD*Z*VBARAN^2)/(21.1*(CSGID-DPOD))
6150  DPTOT = DPRESP + DPRESA + PRESBIT
6160  GOSUB 920
6170  GOTO 5120
6180  RUN "QKPLT.EXE"
```

VITA

Name:	Robert Duane Pierce
Born:	August 10, 1954 Boise, Idaho
Wife:	Candice Marie (Morris) Pierce, married June 10, 1978
Children:	Meagan Marie, born May 21, 1979 Jessica Lyn, born July 18, 1982 Zachary Robert, born March 12, 1984
Parents:	Mr. and Mrs. Duane Marshall Pierce
Permanent Address:	3365 Rosedale Abilene, Texas 79605 (915) 692-0639
High School:	Cooper High School, Abilene, Texas
Colleges:	South Dakota School of Mines and Technology, Rapid City, South Dakota Bachelor of Science in Mining Engineering (December 1976)

END
DATE
3-88
DTIC